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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE ON

THE WESTINGHOUSE WATER REACTORS

Nuclear Regulatory Commission
Room 1046
1717 H Street, N.W.
Washington, D. C.

Wednesday, February 12, 1986

The meeting of the ACRS subcommittee convened at 8:30 a.m., Mr. Jesse C. Ebersole, chairman, presiding.

ACRS MEMBERS PRESENT:

MR. JESSE C. EBERSOLE
MR. HAROLD ETHERINGTON
MR. CARLYLE MICHELSON
DR. CHESTER P. SIESS
MR. GLENN A. REED
MR. DAVID A. WARD
MR. CHARLES J. WYLIE
DR. WILLIAM KERR

DR. IVAN CATTON, Consultant

DR. RICHARD SAVIO, ACRS Staff Member

PUBLIC NOTICE BY THE

UNITED STATES NUCLEAR REGULATORY COMMISSIONERS'

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

WEDNESDAY, FEBRUARY 12, 1986

The contents of this stenographic transcript of the proceedings of the United States Nuclear Regulatory Commission's Advisory Committee on Reactor Safeguards (ACRS), as reported herein, is an uncorrected record of the discussions recorded at the meeting held on the above date.

No member of the ACRS Staff and no participant at this meeting accepts any responsibility for errors or inaccuracies of statement or data contained in this transcript.

P R O C E E D I N G S

MR. EBERSOLE: The meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards Subcommittee on the Westinghouse Water Reactors.

I am Jesse Ebersole, the Subcommittee Chairman.

The other ACRS members are: Mr. Etherington, Mr. Michelson, Dr. Siess, Mr. Reed, Mr. Ward, and Mr. Wylie.

Our consultant, Dr. Catton, is here assisting us i our review.

The purpose of this meeting is to discuss the November 21, 1985 water hammer event at SONGS-1. Copies of the agenda for this meeting are available and will be passed out to anyone who has not yet received a copy. The topic is also scheduled for discussion by the ACRS tomorrow afternoon.

Dr. Savio is the cognizant ACRS Staff member fo this meeting. The rules for participation in this meeting have been announced as part of the notice of this meeting previously published in the Federal Register on January 31, 1986. A transcript of the meeting is being kept and will be made available as stated in the Federal Register notice. It is requested that each speaker first identify himself or herself and speak with sufficient clarity and volume so

that he or she can be readily heard. We have received no written comments or requests for time to make oral statements from members of the public.

I just want to make a few observations. It seems to me, this is another case where NRC is -- intends to wait until some sort of a physical event occurs to attempt the fix of a problem.

For instance, we had Salem for the scram case, we had the Brown's Ferry fire for the fire case, we had Davis-Besse for the aux feedwater case, and in each of these cases, the problems were reasonably well known in advance, that there was intrinsic potential for damage to the station by malfunction of a piece of equipment.

In the check valve case it's a very old issue, indeed. I recall many years ago a discussion with one of the consultants who said, we have been asked to investigate the dynamics of check valves and the associated motor-driven valves and pipes in certain designs, and when he got to a certain point in the investigation his customer found things weren't going so well so he turned off the investigation and that was the conclusion of that study.

These check valves that failed here will be a catalyst to have the check valve problems at large investigated, I hope. Certainly, on a more general basis I hope we can take this as the incentive or the catalyst to

start a broader or more general study of the check valve and associated valve and pipe dynamics at large.

Again, this seems to be the catalyst event to take this on since we have been unable to get it going before this time.

I believe our first speaker is Mr. Richard Dudley. Mr. Dudley?

MR. REED: Jesse, I would like to make a comment. It's my recollection that San Onofre is, very early, the second commercial reactor, utility reactor, Monroe being the first, San Onofre being the second. And it's very much a one-of-a-kind design that -- never was the safety injection or feed systems done subsequently that same way. I would like to have some indication, based on what you just said, how that relates to whether we have a generic issue or whether we have a one-of-a-kind issue.

MR. EBERSOLE: Well, I believe it's true that today if you look at check valves at large you'll find some that are simple, old-type flapper-type valves that crank into their hardened seats with great gusto and have the potential of carrying the parts backwards into the backup valves, thus causing them to cascade into failure. We have others that have hydraulic piston cylinder arrangements to gradually let the thing come down on its seat, consistent with the admission of high-pressure fluids to the back end.

So there's little, if any, real standardization or common design at present in the industry and I think we need to look at that.

MR. SIESS: Is it good or bad that they are not standard?

MR. EBERSOLE: Oh, I think it's bad that we don't have a common standard for design of these things.

MR. SIESS: If we had them all standard then they'd all be failing at once.

MR. EBERSOLE: That's always the perennial argument.

MR. SIESS: I wonder where we should be going.

MR. EBERSOLE: If we have one bad accident it colors the whole industry.

MR. SIESS: Especially if all the plants are alike.

MR. EBERSOLE: I don't know how to put that to rest. Well, go ahead.

Well, in this this case, before we get started, had there ever been a study of check valve dynamics at this plant?

MR. DUDLEY: I am not aware of one.

My name is Dick Dudley, I'm the project manager for San Onofre Unit 1. I have had that responsibility since July 11, 1975.

MR. MICHELSON: Can you move the microphone a little closer to your mouth? It's not going over too well. Maybe I better hold it.

MR. MICHELSON: It's now getting better.

MR. DUDLEY: What I would like to talk about today is a brief rehash of certain licensing activities that have taken place and are currently taking place at San Onofre Unit 1, in order that the committee gets a better idea of activities at the site in addition to the activities that are ongoing now with relationship to the water hammer and the resolution of those concerns.

(Slide)

San Onofre Unit 1 was shut down on February 27, 1982, for a steam generator inspection. I apologize for the error in the slide, but the steam generator inspection was the primary reason for shutting the plant down. During that shutdown, during the SEP review, concerns were raised regarding the ability of the plant to meet its original seismic design basis of 0.5 G.

Because of those concerns the utility at that point committed to upgrade the point to a .67 G level, which is consistent with the seismic design of San Onofre Units 2 and 3 also located on the site. The G level is the same but the response factors are somewhat different.

The NRC, on August 11, issued a confirmatory

order which confirmed the Licensee's commitments and precluded restart of the plant until the seismic concerns were resolved. During this period of time, restart of the plant was somewhat uncertain. Because of that, the utility deferred quite a bit of licensing work that was -- would have been done on Unit 1, except for -- they did proceed with the SEP review activities.

Because of deferring this work, a backlog of licensing actions began to accumulate, or certainly if there was a backlog it wasn't reduced.

December 12, 1983, the utility submitted a return-to-service plan for San Onofre Unit 1, and this plan included the seismic upgrading of safety-related structures: electrical systems and plant equipment that was needed to achieve hot shutdown.

In addition to this, the Licensee proposed an integrated living schedule methodology that would allow the utility greater flexibility in implementing many of the capital projects that would be ultimately coming out of the backlog of licensing actions that had accumulated.

In November of 1984, the NRC allowed the facility to restart after they completed the seismic upgrades that are shown here.

(Slide.)

The systematic evaluation program was still

ongoing and the draft integrated plant safety assessment report was issued in April 1985. Briefings were provided to the ACRS on the staff's SEP work on June 19, 1985 to the subcommittee; on August 9 to the full committee. On August 13 the ACRS issued a letter which supported the Staff's SEP conclusions.

The utility had originally planned to operate Unit 1 from November 1984 until November 30, 1985, when they planned to shut down the plant and proceed in accordance with the integrated living schedule to complete a significant number of plant modifications. This would include completion of the seismic modifications to the plant for the remainder of the systems necessary to mitigate accidents and to achieve the cold shutdown. This would include completion of the equipment qualification program.

We had issued an exemption to the utility that allowed them to operate until November 30, with 70-some pieces of equipment that did not fully meet the EQ guidelines. Those will all be replaced during the outage.

The Licensee also is completing fire protection modifications. This would include the installation of a dedicated shutdown system for fires in certain areas. The dedicated shutdown system will have its own diesel. This will be a nonsafety-related diesel.

Licensee also intends to install a third auxiliary feedwater pump, and for the next operating cycle this auxiliary feedwater pump will be powered by the nonsafety-related diesel from the dedicated shutdown system. The licensee's plans then are to upgrade this third auxiliary feedwater pump to a third train of auxiliary feedwater in the next refueling outage. However, on November 21, 1985, the water hammer event occurred. Due to the significance of the event, the NRC accident investigation team was dispatched to the site.

The Licensee then chose to begin their refueling outage, which was scheduled for November 30. They entered that outage nine days early.

MR. REED: Could you just clarify that dedicated shutdown system? What do you mean by a "dedicated shutdown system"? Does that have to do with decay heat removal or does it have to do with something else?

MR. DUDLEY: Yes. It would allow the Licensee, for example, in the event of a fire in the control room, it would allow the Licensee to open certain breakers and take control of the plant from this remote system and allow them to go all the way to cold shutdown condition.

MR. REED: That's something that has been in the cards for five years or so?

MR. DUDLEY: Yes, it is. I just wanted the

committee to know the licensing status on the implementation of some of these items.

MR. EBERSOLE: Really that's too broad a term for it. It's really an auxiliary control system; alternate control system. It's no alternate power, just an alternate control for the loss of control to the control room.

MR. MICHELSON: This is just an Appendix R modification?

MR. DUDLEY: Yes, it is. These are all the remarks that I have prepared. If you have any questions I'd be glad to go over them. Okay.

(Slide.)

MR. MARTIN: What follows is the report of the accident investigation team for the San Onofre event.

(Slide.)

The team was composed of myself, Thomas T. Martin from Region 1; Matt Chiramal, who is in the back -- would you raise your hand? Bill Kennedy, Wayne Lanning, Al Serkiz, and Steve Showe who is not here today.

(Slide.)

One of the things we found early on in the investigation was we needed to understand the plant, because of its unique design. It's operated by Southern California Edison, located south of Los Angeles near San Clemente, Westinghouse three-loop PWRs. It was licensed in

1967. It's a spherical containment with concrete enclosure building, has electric main feedwater pumps that also function as safety injection pumps.

(Slide.)

Quick overview. Here's the containment, the turbine -- this flash evaporator feedwater heating will play a role in the event. There are heaters on both sides. The auxiliary transformer, which is -- acts like a startup transformer, will play a role. Unit 2 and Unit 3 are back over here. The circ water pumps are back down here and the Pacific Ocean is there. Diesels are here, the control room is in this area. The thing called the feedwater mezzanine is underneath this area, and this is where we'll actually have the major steam leak develop.

MR. EBERSOLE: With the feedwater pumps acting as safety injection, would you clarify how they handle the fluids to get borated water into it?

MR. MARTIN: Actually pump trips, valve shifts. It then takes a suction from a thing called a safety injection pump, which is like a booster pump, comes right out of the RWST, into the safety injection pump, into the feedwater pump and then the reactor coolant loops.

The feedwater pump is a booster pump. I forget what the shutoff head is. It's basically an intermediate head system.

MR. EBERSOLE: And then it takes auxiliary suction then from the borated water source which is also pumped?

MR. MARTIN: Yes, sir.

MR. EBERSOLE: Thank you.

(Slide.)

It also has one turbine and one electric auxiliary feedwater pump. Dick Dudley spoke about a second electric pump that will be installed. It was one immediate and one delayed-access off-site power source. We'll talk about that in a second.

It has diesels that do start but do not automatically load on loss of powe- only. It takes a safety injection in conjunction with a loss of power for them to automatically load.

MR. EBERSOLE: May I ask on that particular, that third bullet, where was the automatic loading denied? It would have appeared, had it been present, that some of these things wouldn't have happened?

MR. MARTIN: I can't answer that. Dick, can you?

MR. DUDLEY: No. The diesel was installed in 1976. I can't really say what occurred during that review.

MR. EBERSOLE: Perhaps it couldn't carry the load. I don't know. We'll see.

MR. MARTIN: They have some new diesels there.

They are capable carrying the safety-related loads on the buses, but the buses have other than safety-related loads on them, and we'll show that when we go through this little educational slide.

The first one here is the condensate system. You have four condensate pumps with discharge check valves. These are made by the same manufacturers as the ones that failed. And then a common header. Nothing prevents the flow from coming like this, basically it has a common header.

Here the flash evaporators -- this is the one that's going to fail and the condensate train goes up and meets the main feed system.

Here's the alternate suction from the safety injection pump feeding into the pump. These are hydraulic-operated valves here. Basically this is what shifts around, and you start having boric acid -- borate water going to the reactor coolant loops during the safety injection. The first point, feedwater feeders, these are the high pressure ones, up around 1300 pounds. The system back behind here in the condensate system is a 360-pound system. Two pumps, again. Nothing to prevent flow back through here except these check valves. These check valves are going to become important. These check valves are going to fail and all of these check valves are going to

fail up here.

There's a common header, then a feed to each steam generator, feed control valve, a bypass control valve for low flow, check valves -- these are, like 10-inch. This is a four-inch check valve then into the steam generator.

The AFW comes in ahead of these check valves just before it enters into containment, so these need to seat to make sure the AFW goes to the steam generators.

This valve and this valve, the disc will be completely disconnected from its hinge arm. This valve here will be loose and actually will stick when it tries to shut.

These valves, which are the four-inch, seem to seal fine, although the B one receives the major water hammer damage and its bonnet is the one that is lifted and you have the major steam water leak.

(Slide.)

MR. MICHELSON: Excuse me, before you leave that slide, there was something in the report that referred to the fact that on the B line the valves were throttled to 50 percent? Or they were each 50 percent flow or something?

MR. MARTIN: That's the AFW system, sir. There's a single control valve that feeds this. To make sure that they have the redundancy, there are two 50

percent valves which feed this, one from each one of the AFW trains.

MR. MICHELSON: On the 50 percent valves were they set to throttle at 50 percent?

MR. MARTIN: They were set to control 50 percent flow, so together they deliver the 100 percent.

MR. MICHELSON: They were the same size as the others but just throttled back?

MR. MARTIN: Yes, sir.

MR. REED: The penetrations through containment, are you going to show those? I guess if you talk about containment penetrations, the rules for this class would be probably one check valve outside containment and one inside containment; is that correct?

MR. MARTIN: No. I don't believe that's correct. This is not considered -- this is a closed system, basically in accordance with Appendix J.

MR. REED: A closed system?

MR. MARTIN: Yes. It goes right to the steam generator --

MR. MICHELSON: They aren't using the good rules at all.

MR. REED: Are there more check valves between that point and the steam generator?

MR. MARTIN: No, sir.

MR. REED: None inside containment?

MR. MARTIN: No, sir. This is the main steam system. Now there's a common generator for all steam generators to feed, therefore a problem in any one is communicated to all three. The feed lines feed three, and then here's the steam lines coming out. These manual valves, and they are manual, not motor-operated isolation valves -- the operator has to go down and put a ring on the valve to shut it. This is how they stop the cooldown that might result from leakages down that way or from problems with the turbine stop valves or governor valves.

MR. EBERSOLE: Let me ask, in a shutdown mode where you are going to go to evaporator coolant to the steam generators, this says it must be able to do that at virtually atmospheric pressure because you have a potential for opening all steam generators to atmosphere.

MR. MARTIN: Yes, sir.

MR. EBERSOLE: Is the emergency cooling mode using the steam generators hypothetically done at very low secondary pressures?

MR. MARTIN: Whether it's designed to do that I can't answer. Dick, can you answer that?

MR. DUDLEY: No.

MR. MARTIN: We have a presentation by the Licensee afterwards. He can probably answer.

MR. EBERSOLE: It's a neat trick to do it without overcooling.

MR. MARTIN: True. They reduce the flow to the steam generators to the lower rate they use, 25 --

MR. EBERSOLE: Do they lower the water level?

MR. MARTIN: They let it go all the way off scale low; basically they protected the primary to the secondary.

MR. MICHELSON: Do you know if the Licensee ever did a three steam generator blowdown analysis upon the effect of primary reactivity, et cetera?

MR. MARTIN: I know there was analysis performed for main steam line and feedline breaks. Since the design hasn't changed in that respect it would have to have assumed all three blew down.

MR. MICHELSON: So this is a three steam generator blowdown case.

MR. MARTIN: That's correct. I know the analysis has been done. I don't know the details of it.

MR. EBERSOLE: I would suspect, then, the containment would have to tolerate, of course, secondary blowdown into the containment, the contents of all steam generators.

MR. MARTIN: I know in designing the AFW, that was one of the things they looked at.

MR. EBERSOLE: So we still have to backtrack into history a little bit to see. Thank you.

MR. MARTIN: Yes, sir?

MR. REED: Follow that steam line out and you come down to the first valve which you said they had to crank closed?

MR. MARTIN: Yes, sir.

MR. REED: Is that a stop check valve or just a manual stop valve?

MR. MARTIN: It's my understanding it's just a manual stop valve. I don't know the full details of the valve internals, but I understand it's just a manual valve.

MR. EBERSOLE: This is the one that's air-operated?

MR. MARTIN: No. This one is basically a very large hand wheel with the ability --

MR. EBERSOLE: You have to take a wrench up to it too big for a man to use and have a drive motor to do it; is that correct?

MR. MARTIN: It doesn't have a drive motor on it. You use an air-operated wrench, but a man could do it if you put a couple of men on it. It's much easier, though, to put an air wrench on it.

MR. REED: I have to ask this question at this time: Was California a power-boiler-code state at the time

this plant was built?

MR. MARTIN: I can't answer that. Ken, can you answer that?

MR. BASKIN: Yes, it was.

MR. MARTIN: That's Ken Baskins, the Licensee.

MR. EBERSOLE: How does a man go up to the valve if the hypothetical break is at the valve proper?

MR. MARTIN: Very difficult. You'll find in this particular event when it lets go behind him he evacuates the area very quickly.

MR. EBERSOLE: Well, I guess we'd have some very interesting root observations to make about this design before we get done.

(Slide.)

MR. MARTIN: This is the electrical system and it will play a role in it. There are two diesel generators feeding their safety-related buses. But you'll notice that there are other things on here: some station service transformers, some lighting transformers; normally in normal operation the startup transformer they call the auxiliary transformer C feeds the two safety-related buses. And it gets its power from the switchyard.

The diesels sit here, they are not operating.

The generator feeds out through a motor-operated disconnect to a common bus here which then feeds out to the

switchyard and also feeds auxiliary power back to the two nonsafety-related buses, which have the reactor coolant pumps, circ water pumps and things like that on it.

MR. EBERSOLE: So the safety-related power source is in fact from the switchyard, not necessarily from the output of the turbine generator?

MR. MARTIN: That's correct. And the switchyard is considered the preferred source, even over the diesels. That's the training that is given the operators.

What we'll find is although the normal lineup with these powered directly off the generator and these powered directly off the off-site source, in this event they had an unusual alignment.

They had this bus powered from this bus because it had a ground on this system here. So the off-site source was carrying this safety-related bus, which happens to carry one of the feedwater pumps, and all the other three buses were being carried on the output of the generator. Okay?

MR. MICHELSON: Are the diesel generators capable of starting the feedwater pumps without first clearing the board and keeping it clear?

MR. MARTIN: This is a load stripping -- but they are able to run the feedwater pumps off the diesels.

MR. MICHELSON: That's not the answer to my

question. Can I start the feedwater pump off the diesels without first stripping the board and keeping it stripped?

MR. MARTIN: Ken, can you answer that?

MR. EBERSOLE: You are talking about the starting load?

MR. MICHELSON: Starting load off a 3600 horsepower diesel.

MR. MARTIN: My understanding is yes.

MR. MICHELSON: I don't want your understanding. I want the answer.

MR. MARTIN: If you have a blackout and everything is dead, the diesels go on and load everything onto the bus and then they start the loads, so then it is capable of carrying the start.

MR. MICHELSON: The question is the sequence in which you start the loads.

MR. MARTIN: There's a sequencer that loads these things on.

MR. MICHELSON: You have to start the board again to get them started?

MR. EBERSOLE: What's the size of the diesel generators?

MR. BASKIN: I'm Ken Baskin. The diesel generators are about 5-1/2, 6 megawatts; they are rated at 8800 --

MR. EBERSOLE: Can they take an across-the-line start of the main feedwater pumps?

MR. BASKIN: Yes.

MR. MICHELSON: Can they take a fully loaded board? I mean all the other loads can come on and they come on line and they'll still start it?

MR. RAINSBERRY: Yes.

MR. MARTIN: We have a loss of in-plant AC power. All the power in-plant is gone, all the power is in the switchyard. We have an inoperable feed pump check valve which leads to a rupture of the flash evaporator, this is because the running field water pump overpressurizes the opposite header. We then have a loss of feedwater after the reactor is tripped and the turbine is tripped. We then have multiple inoperable feedwater check valves, a total of five, which then allow backblow from all the steam generators so all steam generators are losing inventory through the feedwater and condensate system back through the rupture and the isolation flash evaporator.

The water hammer then occurs in the B feedline, causing the piping, piping supports and component damage. We have a damaged feedwater check valves that develops a significant steam water leak. This is in the area of the main steam isolation valve, that the man was shutting.

We have a plant that is then shut down and

cooled down safely by the operators.

(Slide.)

MR. MICHELSON: The flash evaporator, of course, ruptured. The shell ruptured. How many tubes were actually ruptured in the evaporator?

MR. MARTIN: When we completed our investigation we knew of one tube that had ruptured. The tube is about 350 pounds. The shell is about 15 pounds.

MR. MICHELSON: What size is it?

MR. MARTIN: It's about an inch.

MR. MICHELSON: So that was really preventing the steam generators from blowing down at a much more rapid rate?

MR. MARTIN: That's correct, sir. But if there had not been sufficient opening there and sufficient resistance in the line, others would have ruptured. Basically there was nothing to stop the flow there except 350-pound piping, and the steam generators were at significantly higher pressures than that.

This is the charter of the team: to determine what happened, identify probable causes of what happened and make appropriate findings and conclusions to form a basis for possible follow-up actions.

(Slide.)

MR. MARTIN: I should point out we were not

asked to review the design. In fact, we were specifically told not to.

Fact-finding methodology, we conducted interviews, meetings with the Licensee, we reviewed plant data, which was extremely limited -- one because of the loss of electric power most of the recording instruments are lost. The computer that they have that would have captured data, that was inoperable. The personnel logs we reviewed, the quarantined equipment we utilized to basically say, these are the pieces of equipment we think were involved in the event. Let's not do anything with them until we develop very systematic approaches to investigating what went wrong with them. We found that our initial envelope of quarantine equipment was actually too small. We had to expand it slightly when we found additional check valve problems.

MR. MICHELSON: On the question of computer inoperability, why was it inoperable? Was there a wrong switch in the wrong position or was the power disconnected?

MR. MARTIN: Due to earlier troubleshooting activities, trying to find the ground on the safety-related buses they had turned off loads, turned them back on. One of the loads they turned off was this computer. When you turned it back on the disk drives come back up to speed but you need to push a reset to reestablish the software

initiation point. That was not done.

MR. MICHELSON: There is no requirement in the procedures to do this on power interruption?

MR. MARTIN: Not on the procedures they were following.

MR. MICHELSON: If they had a power interruption during another kind of accident then I guess you are assured the computer won't track the accident; is that correct?

MR. MARTIN: It will track the accident because the -- if you don't have this complete loss of in-plant power, then this computer stays on the line and keeps the data.

MR. MICHELSON: Are you saying there's an automatic power transfer to an alternate source and if it's not dead you are okay, but if it's dead too, only then do you have to reset the computer?

MR. MARTIN: Can you describe the actual lineup of that? Matt?

MR. CHIRAMAL: I didn't look at the computer.

MR. BASKINS: I don't believe it automatically transfers.

MR. MICHELSON: So if you lose your power supply you really have lost it. This says during accidents of other kinds you are also going to lose the computer needed

to track it?

MR. MARTIN: Recognize these would only be fed by one of the safety related buses and this is the first time --

MR. MICHELSON: Well, safety-related buses have been known to lose their power, of course.

MR. MARTIN: Since 1967, in this plant, that's the -- this is the first time.

MR. MICHELSON: That's not the point.

MR. EBERSOLE: Let me ask this question. By and large, computers are, at least I thought, always to be fed by inverter sources driven by batteries for the explicit purpose of riding through the transients that they need to record. Is it that this design simply didn't do that?

MR. MARTIN: That's my understanding.

MR. EBERSOLE: So they go blind in the presence of --

MR. REED: I thought what Jesse said was correct. Early computers and up until the coming of SPDS, the computers were 95, 98 percent reliable and not necessarily supplied by vital power; is that correct?

MR. EBERSOLE: How do you mean? Oh, no, no. Way back for 25 years the computers have been inverter-driven by battery sources.

MR. REED: There weren't computers.

MR. EBERSOLE: I'm talking about transient recorders and recorders for recording events like this type of cascade. They always go back to batteries, don't they?

MR. REED: Knowing a lot about the Yankee Rowe and Haddam design, I don't think you would find that kind of power reliability in that vintage.

MR. EBERSOLE: Does this mean automatically that the records of the transient are lost?

MR. REED: Data logs and computers in that vicinity are supposed to be only 98, 99 percent reliable. If they are gone, you have indicators and other instrumentation recorders to take care of it.

MR. ETHERINGTON: 25 years isn't very much different from the time this plant was being designed.

MR. MICHELSON: A lot of people in the recent past have been upgrading their plant computers so they are a little more reliable in terms of, at least, power supplies.

MR. EBERSOLE: I'm hearing here that the transient event are incapable of being supported if they are associated with a power outage?

MR. MARTIN: In this particular case almost all are lost plus this computer.

MR. EBERSOLE: There's no record of events, no battery source?

MR. MARTIN: One of the things the Licensee is doing is looking at his ability to reconstruct events from data available. One of the things they are looking at is this system.

MR. EBERSOLE: How generic is this problem, the absence of recording data in the event of cascading events causing a loss of power, except for the batteries?

MR. MARTIN: Because of the uniqueness of this design I can't answer that.

MR. MEDFORD: This is Mark Medford, licensing manager for the Licensee. I would like to interject one thing. I believe that the computer is on our vital bus 4. We have four vital buses. Three of them have backup power. Unfortunately vital bus 4 at the time of the event did not.

MR. EBERSOLE: Okay.

MR. MEDFORD: One of the design changes which we are going to implement is to provide a backup source of power to vital bulls 4.

MR. EBERSOLE: Okay.

MR. MICHELSON: Does that mean that the computer, then, resets itself after the power -- the backup power comes onto the vital bus?

MR. MEDFORD: I'm glad you asked that. A second change we are considering, and in fact will implement -- we haven't designed the change yet -- is to alter the software

in such a way that you don't require a resetting.

MR. MICHELSON: Okay.

MR. EBERSOLE: What is a "vital" definition? I thought it automatically connoted the presence of a battery source and an inverter which was free of switching transients. You know, the bus was free of switching transients. What is a vital bus?

MR. MEDFORD: That's not true in this case.

This is Jack Rainsberry, he's a licensing supervisor for Unit 1. Can you help?

MR. EBERSOLE: By what right do you call it vital when it's subject to switching transients?

MR. RAINSBERRY: It does have safety-related controls on it and it automatically switches to --

MR. EBERSOLE: It's called vital by virtue of the circuits connected to it, not by what it supplies.

MR. RAINSBERRY: It will switch, too, with an automatic source. It's not a UPS --

MR. EBERSOLE: Thank you.

(Slide.)

MR. MARTIN: In the sequence of events they had a small saltwater leak into the main condenser causing a blowdown of about 10 GPM into the steam generator. This will be important. The status of steam generator blowdown is not indicated in the control room. Unless you remember

that it is on, you will not recognize that this is a loss of inventory.

The unit was operating at 60 percent power. It was down at that power because, one, they had one of the circ water pumps off to take care of the main condenser and they had been down even to lower levels when they were trying to hunt for a ground.

The critical function monitor system, that was the computer, was disabled. It was disabled because of earlier ground troubleshooting activity. The electrical ground troubleshooting was in progress. They had finally isolated it to the C auxiliary transformer, their start-up transformer. And the electric plant was in unusual alignment.

MR. EBERSOLE: That blowdown, that's common -- that's 100 GPN for each steam generator?

MR. MARTIN: That's correct.

MR. EBERSOLE: What's the aux feed input?

MR. MARTIN: The aux feed comes on and will not exceed 150 GPM to prevent water hammer, but could go up to as high as, I think it's 50 or 300.

MR. EBERSOLE: So I have a potential leak in the secondary system that equals to or maybe exceeds the aux feed flow, but I don't have any indication of its presence?

MR. MA[illegible] [illegible]ou don't have indication of its

presence in the control room.

MR. EBERSOLE: Where do you have it?

MR. MARTIN: Out in the plant. Bill, can you comment on where that is located?

MR. KENNEDY: No. I'm afraid I do not know the locations.

MR. MARTIN: This will cause a problem to them because they won't recognize it for about 45 minutes into the transient.

MR. EBERSOLE: Surely that is going to be fixed.

MR. MICHELSON: If the computer is not reset how do you know that from the control room?

MR. MARTIN: You don't know it from the control room. That's the whole point.

MR. MICHELSON: You have to go to the computer itself?

MR. MARTIN: The computer will not indicate blowdown status. The computer is located in the tech support center.

MR. MICHELSON: On the computer itself, it loses power, power comes back on, there's no automatic reset; how do you know that the computer is not now on standby?

MR. MARTIN: Licensee?

MR. MICHELSON: Do you have to walk up to the computer and see a little light on? Is it indicated or

alarmed in the control room?

MR. MEDFORD: There's no alarm that would indicate that.

MR. MICHELSON: Where is the computer relative to the control room?

MR. MEDFORD: In the tech support center immediately adjacent.

MR. MICHELSON: So you have to walk over there if you wonder at any time if your computer is on standby for a transient?

MR. MARTIN: There's one monitor facing into the control room so you can see it from the control room.

MR. MICHELSON: You can see the fact that the indicating light is on indicating that it isn't reset? Or is there even an indicating light?

MR. KENNEDY: There is a CRT that faces the control room through a window. The shift technical adviser commented that he knew the machine was not useful because the screen was displaying a pattern which wasn't indicative of the normal behavior of the system.

MR. MICHELSON: You are operating along under normal conditions and you glance over there; is there a different kind of pattern on it if the computer hasn't been reset?

MR. KENNEDY: As I understand it, yes. You can

request specific patterns, specific data to be provided and it is normally, apparently it indicates that it is operating, functioning normally.

MR. MICHELSON: I'm not sure that has yet answered my question. It's always nice to know that your computer is not on-line when you thought it might be -- was supposed to be on-line, for instance. How do I know that the computer is not -- not in an operable condition?

MR. KENNEDY: They did not know that. In fact, when the trip of the plant occurred the computer had recovered enough to attempt to go through an immediate trip report. The immediate trip report produced data that was approximately 24 hours old and looked very strange. The power was still up after the trip.

That took some time to sort out, reset the system and then it started to provide useful data.

MR. MICHELSON: That was the first clear indication that the thing had not been reset?

MR. KENNEDY: Yes, sir.

MR. EBERSOLE: Do you happen to know whether the condition of the blowdown system is commonly not advertised in the main control room?

MR. MARTIN: I do not know.

MR. EBERSOLE: You don't know. Had this control room been subjected to one of these human factors analyses?

MR. MARTIN: Bill?

MR. KENNEDY: Sir, they have not completed a control room design review. That's pending and will be completed.

MR. EBERSOLE: If they did a control room design review, would they analyze informational outputs which weren't even in the control room, like this one?

MR. MEDFORD: Yes, we would. And will.

MR. EBERSOLE: Thank you.

MR. MEDFORD: Let me add, in this specific case another of the design modifications we are incorporating is to both provide status indication of the blowdown in control room and to provide automatic isolation of blowdown on initiation of aux feed.

MR. EBERSOLE: Thank you, thank you. Go ahead.

(Slide.)

MR. MARTIN: At time zero, because of a fault that occurred on the line feeding the 1C bus, at this point that line is energized because the transformer is energized feeding the 2C bus, but the braker is open over in 1C. But that line is still energized. It fails in two places, causing a differential trip which takes out this auxiliary transformer which takes out the 2C bus and takes out the east feedwater pump.

The NS phone rings immediately. This is going

to cause problems. The shift supervisor will answer this, wondering how the NRC is so perceptive, they just had a scram and the NRC knows about it. This was probably caused by the transient. We have not been able to duplicate this; the feedwater pump check valve fails, the flash evaporator tube ruptures -- this is the result of the one feedwater pump that is running overpressurizing the other side, since this discharge is up around 1100 pounds and the tubes on the flash evaporator are about 350 pounds, we basically have overpressurized and we rupture here.

Diesel generator number 2 starts but by design does not load.

MR. EBERSOLE: Let me ask a question at this point. I understand this is the first failure, electrical failure that occurred like this; correct?

MR. MARTIN: Yes, sir.

MR. EBERSOLE: Had there been other events in which one of the C buses, the preferred buses were lost and the system did work and the check valves did function according to their design? Or have we been protected from that by the simultaneous -- rather the fact that we had a single alternate power source?

MR. MARTIN: In fact, there's even tests that the Licensee runs to test these check valves where they run one pump with the other one shut down to test the check

valve.

The last check for this check valve was in the November time frame, if I remember right; is that true, Wayne?

MR. LANNING: That's right.

MR. MARTIN: There's a test part of the IST program which could be conducted as frequently as once a year.

MR. EBERSOLE: In this case the aux feed pump -- rather the main feed pumps are pressurized and drive towards the other side?

MR. MARTIN: One is operating. The other is shut down.

MR. EBERSOLE: What are the transient times for that test? Do they trip one pump and quickly -- they just trip one pump? That's all?

MR. MARTIN: They start one pump, verify they have flow to the steam generator so they know the pump is working, then they open the other pump's discharge valve and verify that there's no increase in pressure on the idle pump.

MR. EBERSOLE: Okay. Thank you.

MR. MICHELSON: The flash evaporator has a relief valve on it?

MR. MARTIN: 15 pounds. That is on the steam

side.

MR. MICHELSON: I would have thought that the flash evaporator would have been -- the safety would have been sized at least for one tube rupture; just by code, you plan for an accident by the code and decide how big a relief valve you need. Wasn't the safety sized for a rupture in the tube in the evaporator?

MR. MEDFORD: I'll speculate it was structured for a tube with a 360 psi in the tube.

MR. MICHELSON: That's probably the explanation. It was sized too small because although it's sized for one tube it wasn't sized for that much pressure inside the tube. That's probably what happened. Go ahead.

MR. MARTIN: Okay. Within 19 seconds the operators recognized that they have a condition which their procedures require to trip, so the operators trip the reactor and they trip the unit generator which then results in a total loss of in-plant AC power. Remember there's power still in the yard.

The containment isolates automatically; the diesel generator -- the other diesel generator starts but again by design does not load.

MR. EBERSOLE: The containment isolates blowdown; is that correct?

MR. MARTIN: That's correct. At this point it

has gone shut. The turbine-driven auxiliary feedwater pump receives a start signal. Because it is steam driven it will start but by design it takes about 3.5 minutes for this to come up to speed and start delivery.

MR. MICHELSON: Is that a Worthington turbine?

MR. MARTIN: It's not a cherry turbine. It's a standard reaction turbine.

MR. MICHELSON: Who is the manufacturer of the turbine for the auxiliary feedwater pumps?

MR. MEDFORD: I'm not sure.

MR. MICHELSON: Is that a full-pressure rated pump? Does it use 1000 pound or does it throttle 600 pounds or do you know?

MR. RAINSBERRY: I don't recall. I don't know.

MR. MICHELSON: Thank you.

MR. EBERSOLE: On the decay heat rejection, you had a motor driven backup --

MR. MARTIN: But it has lost power at this point.

MR. EBERSOLE: But the hypothetical complete loss of steam pressure, that kills the steam supply to the pump -- doesn't it? -- like the Davis-Besse case if you lose the main steam line anywhere?

MR. MARTIN: Yes, sir.

MR. EBERSOLE: Where is the single failure criterion for aux feed?

MR. MARTIN: Licensee?

MR. MEDFORD: We are adding a second motor-driven aux feed pump.

MR. EBERSOLE: I'm talking about where is it now? I'm taking this as a classic example. In fact, do we have the single failure criteria intrinsic?

MR. KERR: When this plant was built, single factor was not a safety --

MR. MEDFORD: It's a generic problem for plants of that vintage and later.

MR. EBERSOLE: We don't have the single failure criteria in place.

MR. MEDFORD: Yes.

MR. EBERSOLE: We probably need a spread sheet for the plants that don't have this.

MR. MICHELSON: Are you presently contemplating automatic loading of the bus?

MR. MEDFORD: Yes, we are.

MR. MARTIN: Also at this point we had four additional feedwater check valves that failed as a result of the blowdown of all three steam water generators.

MR. EBERSOLE: Wait a minute. TMI II happened a few years ago. I thought this brought attention to this drastic void in the rationale and we did, I thought, implement actions to get the single criteria applied to the

secondary supply side; am I wrong? Or have we got all sorts of things in the field out there that are just kind of a morass of --

MR. MEDFORD: Increased attention was paid to the aux feed system.

MR. EBERSOLE: I remember 10 of them were found to be nonseismic.

MR. MEDFORD: That's true. And there's been substantial upgrai ng, including on this plant, for example, automatic initiation of the aux feed system was added to this plant as a result of TMI. I don't believe it's fair to say that there's an absolute NRC requirement that aux feed systems meet single failure criteria. I believe you would find other units, I think you can find other units that are not committed to the addition of the second motor-driven pump.

MR. EBERSOLE: Thank you.

MR. MARTIN: Okay. The feedwater lines begin to empty as a result of the low level in the steam generators.

(Slide.)

Now you have steam going into the feed rings and actually going back through the feedwater lines. The feedwater lines are now emptying. The steam generators lose inventory via the failed check valves and ruptured tube in the flash evaporator.

The loss-of-voltage automatic transfer scheme is initiated. This is a scheme which sets up conditions for repowering from the yard. It basically opens up a number of circuit breakers. Then, once it verifies that the voltage on the discharge of the generator is below a certain level, it then opens the motor-operated disconnect which then allows you to now back feed from the switchyard through the main transformer to the auxiliary transformer.

MR. EBERSOLE: Is this the GDC 17 --

MR. MARTIN: This is delayed access -- they receive a number of alarms indicating the safety injection actuation at this point.

Fire truck arrives on the site. This is as a result of a fire watch down in the 4 kV room reporting what he thinks is smoke, which is really steam all over the place right outside his door.

(Slide.)

The operators are now attempting to restore power because the automatic sequencer has failed to function. It has not reclosed all the breakers it was supposed to and the turbine driven aux feedwater pump is now delivering approximately 130 GPM to the steam generators, but it's really not going to the steam generators, it's going right back out the check valves to the flash evaporator.

MR. EBERSOLE: Could you throw that other slide back? I want to ask you a question about the main feed pumps acting as safety injection pumps. These are exclusive actions? If it's going to be doing one it can't do the other?

MR. MARTIN: One or the other, that's correct.

(Slide.)

MR. EBERSOLE: How does the rationale cope with the fact that I have to have secondary injection as well as injection to the primary load.

MR. MARTIN: The auxiliary feedwater.

MR. EBERSOLE: So you throw away the pump and then use aux feed for secondary supply?

MR. MARTIN: And again, as an historical note this plant has never experienced a complete loss of main feedwater and aux feedwater prior to this time.

MR. EBERSOLE: Well, I should hope not.

(Slide.)

MR. MARTIN: Okay. The operators finally restore power on the fifth attempt. There's a number of problems closing the breakers. These are 250 kV breakers; they are not familiar with them. They are not frequently cycled, there's a number of interlocks and the operators are not knowledgeable and as a result it takes five times for them to succeed. Once they do succeed, though, they

now repowered from off-site and the motor-driven auxiliary feedwater pump then starts because of a low level in the steam generators. It flows to 155 GPM per steam generator, but again we were still going out toward the break.

The atmospheric steam dumps open temporarily because their controls were set such that the temperature would cause them to open. The operators now following their procedures, close the feedwater isolation valves. These are big motor-operated isolation valves, just upstream of the feed control valves. And this action terminates the blowdown of the steam generators through these feed lines.

At this point the feed lines begin to refill because the auxiliary feedwater is still going to all the steam generators.

MR. EBERSOLE: If the check valves which failed had disintegrated in pieces, this wouldn't have been possible, would it?

MR. MARTIN: If the pieces had gotten under the valve and somehow jammed it open, that's possible. Although they would have had to go through the feed reg valve, which is a caged assembly. It's probably unlikely that pieces could have gotten through the feed reg valve to this motor-operated val~e which is upstream of it.

MR. EBERSOLE: ~kay.

MR. MARTIN: The radiation monitors -- by the way, now we have power, so the containment isolation valves could be reopened.

The radiation monitors are in alarm because they had lost power and they have an alarm there. When the radiation monitor alarm is reset, steam generator blowdown reopens to its open condition, because that was one of the close signals for the steam generator blowdown. So we now have reestablished 1030 GPM blowdown from each of the steam generators. We are feeding at about 155 right now, so we should be catching up but then you are steaming still through the main steam isolation valves.

(Slide.)

MR. MICHELSON: And there was no containment isolation signal then existing at this time?

MR. MARTIN: Because of the loss of power. There was a very slight increase in pressure in the containment. We have a lot of air-operated valves in containment. They normally operate with a mini purge valve open just to prevent the slow build-up of pressure in there. When they had a loss of power, the valve had shut. There had been a slight increase in pressure.

MR. MICHELSON: Thank you.

MR. MARTIN: Okay. The RCS pressure -- temperature and pressurizer level indicates to the

operators that they have a rapid cooldown.

They have one operator that's taking care of the reactor plant, another taking care of the secondary plant and the auxiliary feedwater; the operator taking care of the power plant starts a charging pump. The second pump will then auto-start.

He later starts the reactor coolant pump B to reestablish force convection. He has had natural circulation and they had verified that earlier.

He then directs the operator at the AFW system to terminate the auxiliary feedwater because he thinks that this must be the source of the excess cooldown of the primary system.

Yes, sir?

MR. EBERSOLE: You say reactor coolant pump started. I don't remember when it stopped. Because it gets its power supply out of the yard?

MR. MARTIN: Once you brought power out of the main transformer, that has to come to the auxiliary buses and then feed the safety-related buses, because that's the way they are connected. Can we have that drawing again real quick?

MR. EBERSOLE: I thought the main coolant pumps along with the other pumps were on a separate bus --

MR. MARTIN: Circ water pump also.

MR. EBERSOLE: And those had power available all through this thing?

MR. MARTIN: No, they did not. The -- basically when this was lost these went dead, these three went dead when this was tripped.

MR. EBERSOLE: Okay, the connection down there then was open? From the unit transformer? The bus 1A and 1B?

MR. MARTIN: Talking about these right here?

MR. EBERSOLE: They did not remain hot?

MR. MARTIN: When the generator was tripped as part of the reactor trip procedure, this then deenergized this portion because there's also breakers out here that open up. You do not want to backfeed power into a generator that's --

MR. EBERSOLE: Until you open the disconnect.

MR. MARTIN: That's right. So they open. Then, after a low voltage is sensed on here, indicating that you --

MR. EBERSOLE: Okay.

MR. MARTIN: Then you open this.

MR. EBERSOLE: I got you. So the pump stopped at that point. They were not deliberately stopped?

MR. MARTIN: No. They stopped as soon as you tripped this generator right here.

MR. EBERSOLE: When you reenergized did they

automatically come back on?

MR. MARTIN: No. They had to be turned back on. So these are powered from the now off-site power. This is powered from off-site power. And this is powered from off-site power coming from the backfeed system.

MR. EBERSOLE: Why should they have come back and and compounded -- and there's an argument whether they did -- compounded the overchilling event?

MR. MARTIN: The operators wanted to get back to a forced circulation mode.

MR. EBERSOLE: Doesn't that enhance overcooling?

MR. MARTIN: They needed a charging pump to get pressure control because that gives them the spray in the pressurizer. They chose the B pump because that gives them the most reliable and the most forceful spray. They knew that with the starting of the charging pumps they were going to raise the level in the pressurizer and they wanted to have the ability to control pressure so they needed one pump. They wanted one pump on the line.

MR. MICHELSON: Are buses 1A and 1B class 1E?

MR. MARTIN: No, sir. They are not safety-related.

MR. MICHELSON: Thank you.

(Slide.)

MR. MARTIN: At this point he directs the

feedwater. The supervisor watching this hears this and directs they be reestablished. The auxiliary feedwater goes to zero and is brought back to about 40 GPM, it's really 25 GPM indicated. That's what he shot for. The 5 GPM per steam generator is significant in that a steam generator, regardless of level indication, that is receiving at least 25 GPM, is not considered a dry steam generator.

So, he got back to what he considered was the minimum flow allowable to the steam generators.

MR. EBERSOLE: What sort of secondary pressure do we have now? Is it relieving?

MR. MARTIN: They shifted the controls on the steam dumps, the steam dumps have shut. At this point we should be holding pressure but it's causing cooldown. I don't know what the pressure was at this point. Do you have the number? Wayne do you know?

MR. LANNING: Certainly below load steam pressure because of the flow down through the check valve.

MR. MARTIN: One of our problems is most of the recorders are dead at this point. The timing of where the chart is, it has been dead for a period of time and we couldn't time them very well. As a result, much of the trend data is unavailable to the operators. It doesn't mean much to them.

Okay. So flow is reestablished at 40 GPM, but remember we have a 100 GPM blowdown going, so as expected, the steam generator levels are going to be dropping fairly quickly and we also have some steam coming from the steam generator. As a result of this the control room directs the nuclear plant operators to go out into the field to shut these main steam isolation valves because they think they have excessive cooldown as a result of too much steam coming out of the steam generators.

At this point an unusual event is declared, although NRC is never notified of that fact.

MR. MICHELSON: Before you leave this point you say that the operators believe that if there's 25 GPM on the steam generator, then it's not a dry one. Does that belief appear in procedures?

MR. MARTIN: Yes, sir, it does. It gives three criteria and that's one of them.

MR. MICHELSON: When the procedures were formulated, does it caution that this is only true if there's no blowdown from that same steam generator?

MR. MARTIN: I don't remember that from the procedures.

MR. MICHELSON: You just fail to recognize that you might have the normal blowdown of 100 GMM and only 25 going in and this is a flaw in the procedures.

MR. MARTIN: This will be caught later when they are going through the safety trees.

(Slide.)

Now for a period we have had the feedwater lines refilling because of the auxiliary feedwater. The blowdown is still going on on the steam generator.

At some point here, what, about nine minutes after the isolation valve had been shut, a water hammer occurs. The water hammer causes the -- a small, four-inch check valve bonnet to be lifted stretching the bonnet bolts by about a half an inch, blowing out the gasket and resulting in a significant steam water leak right behind the guy shutting the main steam isolation valves. He hears it and evacuates the area promptly. His normal route would be in stairs that would go above this leak. He concludes not to go that route but takes a longer route. He'll arrive down here some three minutes later, in the control room, described as "dripping wet," and reports the steam line leak.

MR. EBERSOLE: When he was closing this valve with his pneumatic operator, where was the steam going that he was supposedly going to shut off?

MR. MARTIN: To traps and things like that that had not been isolated.

MR. EBERSOLE: Minor leaks that were routine?

MR. MARTIN: That's correct, sir.

MR. EBERSOLE: When he started to close it, coincidental with that he had this valve failure that you are talking about?

MR. MARTIN: In fact, he believes it to be a steam line break and reports it as such.

MR. EBERSOLE: Was that incidental to his closing this process down?

MR. MARTIN: It occurred at the same time, but does not seem to be related at all but just happens to be in the same area.

MR. EBERSOLE: We seem to have just a generation of check valve failures in the same time span.

MR. MARTIN: But this particular check valve failed as a result of a water hammer and basically the pressure pulse comes down and then is redirected up toward the bonnet and the calculated pressure, I believe, was 18,000 pounds or something like that? What was it?

FROM THE FLOOR: On the order of 5- to 6000 psi.

MR. ETHERINGTON: That was calculated from what?

MR. MARTIN: Basically the stretch of the bolts.

MR. EBERSOLE: These pipes and tracks and so forth that were leaking, that's a routine state of equipment?

MR. MARTIN: That's correct.

MR. EBERSOLE: Every time you shut down you have these steam leaks occurring out of the commonly connected boilers.

MR. MARTIN: And their normal procedures would send somebody out there to shut these valves. This is the way they reduce the cooldown and put it under control.

MR. EBERSOLE: What do they do, close off each such leaking valve?

MR. MARTIN: They shut the big main valves. Then they only have to worry about leakage through the steam dumps.

MR. EBERSOLE: Okay. All right.

MR. MARTIN: At about this time they receive a thrust-bearing high-temperature alarm on the B reactor coolant pump. The temperature has been plodding along and suddenly just goes off scale. They believe it's probably a faulty indicator, because it didn't trend up but, being prudent, they decide to go ahead and start the A and C pumps and shut down the B, although that will take them some time to do.

They had some concerns about containment cooling, that slight increase in pressure, and there has been no containment fan coolers in operation.

There's a lash-up that they have to work out to reestablish that cooling, so it takes them a while to get

the containment cooling reestablished.

The operators at this point see that the diesels have been operating for some time without any load. They go ahead and secure the diesel generators. The fire protection foam system in the area of the lube oil reservoirs had actuated early on because of the steam that was dumping up there from the seals on the main feedwater pumps. At this point they see no fire, no necessity for this foam system to be operated, so they secure the foam system.

MR. EBERSOLE: Did the operator succeed in closing this valve in his haste to get away?

MR. MARTIN: No. He just got started. That's all.

MR. EBERSOLE: The overcooling event persisted?

MR. MARTIN: That was a large event of the steam generators blowing down to the feedline and what the -- again, they had recorder problems so they couldn't see a trend. They didn't know what, you know, when the cooling occurred.

MR. EBERSOLE: Are the feed lines high in the boiler, high enough for them to have accepted steam?

MR. MARTIN: Definitely.

MR. EBERSOLE: So now they are steam lines.

MR. MARTIN: Very quickly, the water level on a

trip drops below those feed rings.

MR. EBERSOLE: They have become discharge points for the steam system proper.

MR. MARTIN: All the steam generators are able to feed the B feed ring, which is feeding the leak, which is now not isolated.

MR. EBERSOLE: Now I'm losing secondary steam through the feed lines.

MR. MARTIN: Through all three steam generators.

MR. EBERSOLE: They are having an overcooling event and now I'll ask the question. There's some internal arguments about when they turned on the main coolant pumps. Did that enhance or did it retard overcooling? And was that -- is that in the instruction to prevent overcooling, to start or stop them? The issue being, if you start them up you have very good coupling to the secondary side. On the other hand you have very poor mixing or local cooling problems in the vessel.

Is that all rationalized and on paper?

MR. MARTIN: Wayne, can you answer that?

MR. EBERSOLE: Do you or do you not turn on the main coolant pumps to diminish an overcooling event?

MR. LANNING: I think the purpose of restarting the pumps was to achieve pressure control.

MR. EBERSOLE: But that comes at a price,

possibly.

MR. LANNING: That could come at a price, possibly. But in this case they were cooling with the B -- with the A and C steam generators, reduced steam water flow to those steam generators, so I don't think in this case it exacerbated the overcooling.

MR. EBERSOLE: Okay.

MR. MARTIN: Maybe the Licensee can answer that? Is that one of your considerations?

MR. MEDFORD: I concur with Wayne's assessment. We basically get control of the overcooling by two sets of actions, one was isolating blowdown and the other was isolating field lines. Once that had been done we had pretty good control of the overcooling.

MR. MARTIN: Bill?

MR. KENNEDY: I would like to comment on a term they were using. They did not have an overcooling, meaning greater than 100 degrees per hour. They had greater than their normal shutdown cooling rate which is in the neighborhood of 50 degrees per hour.

They had a controllable cooldown, meaning it was less than 100 degrees per hour and it wasn't that they could adjust it very much, but it wasn't an overcooldown event, rapid cooling situation.

MR. EBERSOLE: Okay. Thank you.

(Slide.)

MR. MARTIN: At this point they start the A pump, then they start the C pump. This is in preparation to shut down the B pump. Steam generator blowdown still on, the generator levels are all off scale low -- they are all steaming to the break in the feedwater system. Reactor coolant B is stopped. The AFW flow to A and C generators is taken up to 70 GPM, not because they know there's something wrong with the B steam generator but just because that's where the reactor coolant pumps are operating and their desire is to establish a fairly rapid cooldown so they can get to the point where they can isolate the steam leak. They still think it's a steam line leak. But they do not want to go above 100 GPM.

MR. EBERSOLE: I'll ask you this, when they drive these generators to very low levels, virtually empty you tell me, they become B and W super heater designs, don't they? They get very high-temperature steam? How hot do they get and are they prepared for it?

MR. MARTIN: I don't have any information on that. Ken, can you answer that?

MR. EBERSOLE: Are you rigged for that sort of super heat?

MR. MEDFORD: I don't have an answer either.

MR. MARTIN: At this point the STA has gone

through the safety trees and asks a question: Is steam generator blowdown still going on? Lights go on and they recognize they forgot to deal with it, so they send a man to the monitor panel, he cranks the set point on the radiation monitor down to a low level. That looks like a high radiation level on that line. It then isolates automatically. They then send an operator out to terminate the individual steam generator blowdowns by shutting the micro valves.

Steam generator A and C levels then start to come back on-scale and they attempt to identify where the steam leak is coming from.

(Slide.)

MR. EBERSOLE: I'm a little concerned about, the operator apparently has to go out to isolate containment, which is in essence what he did when he closed the blowdown valves.

MR. MARTIN: The way he did that was he used the automatic feature of the radiation monitor. That monitor is in the control room.

MR. MICHELSON: That's a funny way to isolate containment, isn't it?

MR. MARTIN: He wanted only to isolate this one line.

MR. MICHELSON: Why didn't he want to isolate

containment?

MR. MARTIN: He had no need to.

MR. MICHELSON: He had nothing else he needed.

MR. MARTIN: He did need containment cooling.

MR. MICHELSON: He does have the option at any time of walking up and isolating containment in total, from the control room?

MR. MARTIN: I assume he does, yes.

MR. MEDFORD: That's correct.

MR. MICHELSON: But he just wanted to get this one particular valve. Apparently it is not operable from the control room.

MR. MEDFORD: In effect he has simulated a containment operation.

MR. MICHELSON: Not all containment valves are operable except unless you want to do a complete containment isolation; operable from the control room, that is?

MR. MEDFORD: That's correct.

MR. MARTIN: At this point the operators are unable to start the circ water pumps. That's important because they provide the turbine plant cooling water, which provides cooling water for the containment. The saltwater cooling system, all these are intertied and capable of multi-modes of operation but they are going to need -- if

they can't have the circ water pumps, they are going to have to use the screen wash pumps and the saltwater pumps to provide the cooling for the RHR system and for the turbine plant cooling water system so that they can maintain the containment cool, so there's some lash-ups that they go through here which are designed -- the lines are there, the valves are there -- but it's an abnormal operation for them to go into this particular mode to establish the heat sink for all these auxiliary systems.

MR. MICHELSON: Just in the way of a more generic question: If this had been a loss of coolant accident in which RHR was needed, has some study been done for all loss of coolant accidents? Can you still get outside of containment and run around and do these lash-ups necessary to make RHR work?

MR. MEDFORD: RHR is not one of the systems required.

MR. MICHELSON: You don't need it for post-accident at all?

MR. RAINSBERRY: We have a recirculation system that is separate from the RHR system.

MR. MICHELSON: So, it is a safety-related system, though? Isn't it?

MR. MEDFORD: It is the normal system used to get to cold shutdown. It is not used for --

MR. MARTIN: At this point, because of the temperature they entered mode 4. They try to establish RHR. They think the interlock for low pressure has been satisfied. They try to operate the valves that open the RHR inlets to the RHR system. They don't respond. They assume that there's a problem with the interlocks. They go back into the panels and actually override the relays, causing the establishment of conditions necessary to open RHR.

It turns out that the set points on the interlock were not what the operators assumed they were and there was a need to change the procedures there and they are being modified.

MR. EBERSOLE: Let me ask you about the standardization of this mode system that you refer to. You throw up there, you know, mode 4, or whatever.

When you talk about mode for one plant is it standard for mode for another plant?

MR. MARTIN: Pretty much standard. That part of the tech specs is pretty well adopted.

MR. EBERSOLE: So I don't need to worry about this being a specific mode for San Onofre?

MR. MICHELSON: This isn't a particular tech spec --

MR. MARTIN: Yes, sir?

MR. REED: A significant happening and operator discovery caused the blowdown taking place. I believe that was discovered, as I saw in the literature, by an STA; is that correct?

MR. MARTI#: It was discovered by the control room staff as a result of the STA going through his safety trees and asking questions. He has no indication in the control room of the status, so his question was -- he got down there: Is blowdown isolated? Is blowdown isolated? They recognize, then, wait, we reestablished the radiation monitors that would have caused them to open. The light came on. People recognized what they needed to do.

MR. REED: I like to bring that up because STAs are around -- it's a divided position with respect to STAs and whether they should be as they should be and I think this proves that one form of STA is useful.

MR. MARTIN: The team's assessment in this case was the control room staff worked very well together. The STA's role of going through the trees and reminding the shift supervisor what was important and what things needed to be considered worked very well. They worked as a very good team in this case.

MR. MARTIN: Okay. About five hours later the unusual event has been terminated. Six hours later the feedwater leak has been isolated and finally they entered

the mode 5.

(Slide.)

The next evening, that night, shortly after midnight they make a containment entry and they find the water hammer damage on the B feedwater lines.

(Slide.)

MR. REED: That water hammer, it would be hard to say when it occurred. If it occurred from refilling of the steam generators, I assume these steam generators do not have U tube injections on the feed ring?

MR. MARTIN: They are normal feed rings with bottom holes.

MR. REED: So it would be hard to say when that damage occurred, whether it occurred on refilling or when it occurred, early on or when.

MR. MARTIN: But they heard the water hammer.

MR. REED: They heard the water hammer certainly out in the steam plant.

MR. MARTIN: That's correct.

MR. REED: There could have been more than one water hammer?

MR. MARTIN: We don't believe so.

MR. REED: I see a problem here in the feed line check valve arrangement. I just don't think you should have a plant with a normal feed ring that doesn't have a

check valve right close to the steam generator --

MR. CATTON: That works.

MR. REED: -- that works. That's what I mean.

MR. MARTIN: Okay. This particular viewgraph is rather negative. I think there are some positive points I need to make here.

The operators discovered very quickly that they needed to scram the plant and within 19 seconds they scrammed the plant. They worked very well as a team in the control room. The operators did place higher priorities on protecting primary system than the secondary system, and the plant was safely shut down.

Given those points, though, there were some operator errors. They failed to follow the appropriate procedure when troubleshooting electrical grounds.

It appeared to us that they avoided, wherever they could, entry into an action statement when there were still other things that they could do.

If they had followed the procedures verbatim they would have entered into an action statement, found that the problems were not where they were looking, and come right back out of the action statement. There would have been no liability in doing so. But they seemed -- if there was anything else they could do before entering that action statement, they would try to do it.

There was some difficulty in reestablishing plant power, the five times trying to shut the breakers to provide off-site power into the plant.

There was the problem of --

MR. MICHELSON: Excuse me, on that particular case was that a problem of -- do you think -- of the inadequacy of the instruction or the inadequacy of the training or the operator just forgot what he had been told and trained to do?

MR. MARTIN: A combination of all of them. Had they followed their procedure and broken out the procedure and followed the procedure they would have probably gotten it right.

The first time they did it he forgot to use a sync bypass switch. That's necessary because one side of the line is dead. The other is not.

MR. MICHELSON: You are saying the procedure is fully adequate?

MR. MARTIN: If followed, it would have been successful.

MR. MICHELSON: Had he ever been trained on that procedure, ever gone through it on either simulation or actual performance?

MR. MARTIN: Bill, can you comment on that?

MR. KENNEDY: I can't say directly he has. I

say they decided intentionally not to follow the procedure because they knew the plant was in an unusual electric plant lineup and that they thought the procedure would not address that successfully. So they decided to bring power back in one bus at a time rather than lash all the buses together, then bring power in.

MR. MICHELSON: The procedure was only for lashing together? A lashing together process?

MR. KENNEDY: That's correct.

MR. MICHELSON: This was an unusual procedure and they thought the procedure wouldn't pertain?

MR. KENNEDY: Right. What they missed was a piece of information that I would call emb ded in the procedure, having to do with the seqencing of some steps, which they missed, which caused the first three attempts to be unsuccessful.

MR. MICHELSON: I think what you told me is they didn't really have a procedure for precisely what they wanted to do?

MR. KENNEDY: Yes.

MR. KERR: Were there any serious consequences of their failing to establish in-plant power on the first try?

MR. MARTIN: It basically delayed the time of the auxiliary feedwater. It's kind of an aside. It's

another complicating factor in this event. That's all it is. It delayed the time it took them to get power back.

MR. KERR: By about how much?

MR. MARTIN: By about 30 seconds.

MR. CATTON: Did the lack of the computer affect it?

MR. KENNEDY: I would not say so.

MR. CATTON: So the information they didn't have they didn't need?

MR. KENNEDY: It may have helped explain the transient early on in the event, to see if things behaved as expected or not expected.

MR. MARTIN: And the other one was their failure to -- well, the inadvertent reestablishment of steam generator blowdown was important and their failure to reset the Fox III computer, which was the critical parameters computer.

The STA performance was good. There were some problems with the emergency coordinator and his statements to the NRC through his misunderstanding of what had occurred didn't -- certainly caused problems in communications between NRC and the Licensee, which is really the last point there.

MR. REED: Who was the emergency coordinator? What was he, a member of the guard force?

MR. MARTIN: No, he was a member of the plant management. He was a licensed SRO. He had come on-site early that morning to help in the troubleshooting activities for the ground. He had left the control room after he was confident they knew approximately where it was. He had gone to his trailer and he heard the noise of the trip. He returned to the control room within minutes and because he wasn't there early on didn't know the full sequence of how they got to where they were. He released the shift supervisor of his control of emergency coordinator and tried to carry this burden of communication with everybody in the outside world.

MR. REED: It sounds like he was a quality person, training, background, SRO, but he comes in to the scene. That would beef the case for any emergency coordinator. So they don't get up to speed -- in fact, you can be on the scene right through the whole thing and not know what's going on.

MR. MARTIN: In his particular case, he went the extra step of hypothesizing and communicating as fact certain things that didn't occur.

MR. REED: Isn't that what the NRC red phone guy wants him to do? Speed up --

MR. MARTIN: That's where you have to refuse to answer that kind of question, say, I don't know.

MR. REED: Then they'll say: Well, why don't you know? Just like a news reporter. You have to know. Give me the answer.

MR. MARTIN: There is some training necessary for NRC in this also.

MR. REED: I would say so.

MR. KENNEDY: I would add, sir, he was not -- the management person who took this role would not normally take that role. He was acting in another person's position because of an illness, and therefore was empowered to take this role and took it. When he came in and did not know what was the current status, he reported that fact to the NRC when they wanted to know what the condition was. He said, give me some time and I'll go find out and get back to you and they continued to ask questions and he answered them to his understanding of how he expected it would have occurred.

MR. KERR: Are you criticizing him for that?

MR. KENNEDY: He could have continued to stress that he did not know.

MR. KERR: I'm sorry, that wasn't the question I asked. You are criticizing him for answering questions which you insisted that he answer? That's what you just told me.

MR. MARTIN: The insistence is improper. The

question was asked again.

MR. KERR: Look, he said, I don't know, I'll find out.

He was asked, what do you think? He told you what he thought. Now you are saying he really should have known? That's what it sounds to me like.

MR. KENNEDY: It was not couched as a: What do you think? It was asked as an explain --

MR. KERR: Come on. If his first answer was "I don't know, let me find out," and you keep asking the same question you may not put it in those words, but you are, in effect, asking him to hypothesize. I mean, he said he doesn't know. What else can he do?

MR. KENNEDY: I agree. I would criticize him for not continuing to stress that he could not answer the questions.

MR. KERR: Well, I sure wouldn't.

MR. CATTON: Obviously you have never been questioned by NRC.

MR. KENNEDY: Oh, yes, I have.

MR. KERR: Did his poor performance or his performance errors contribute to the seriousness of the consequences?

MR. KENNEDY: At the plant, no, sir. The NRC's understanding, yes, sir.

MR. CATTON: I'm not sure that matters.

MR. ETHERINGTON: Would you say the performance was good, of the STA?

MR. MARTIN: Yes, he quickly assumed a role supportive of the shift supervisor, keeping him apprised of what things were important from a safety standpoint. He was reviewing what was on the safety trees to verify that things had been done.

When he found something that did not -- he did not know the answer, he asked questions. When he found things were in an alert level or important, he notified the shift supervisor: Have you considered such and such? Have you looked at such and such?

So, he was like a conscience. He was reminding the shift supervisor of important issues that the safety trees had identified for him.

MR. REED: Harold, you may not have caught the fact that he was instrumental in finding where the water was going, going out of the steam generators, dry out.

MR. ETHERINGTON: I had missed that.

MR. EBERSOLE: This red telephone, isn't this really just an added burden on the staff and will tend to compound the difficulties of the operators to recover, to have a continuous, on-stream flow of information to some Washington bureaucrat?

MR. MARTIN: What we found was the way it was used this time didn't add to the appropriateness of the response.

MR. EBERSOLE: There has to be a man dedicated to do this and he's not likely to be the most valuable one who is going to save the plant.

MR. MARTIN: Our findings here were that both NRC and the Licensee needed to reexamine this function and how they were going to use it.

MR. EBERSOLE: Isn't it likely he's going to get lousy information first on because it's going to be conjecture?

MR. MARTIN: That's one of the things that needs to be avoided. Two, the types of questions. You don't ask -- they were leading questions that were asked by NRC and those leading questions led to responses which were appropriate to this plant. But because the questioners had the perception of a standard Westinghouse four-loop plant, they misinterpreted the response.

There were a number of examples in the report that point out that because we didn't understand the plant because the questions being asked were not symptom -- or, what is the pressure in the plant; what are the thermocouples reading? We were trying to understand the event, making sure the plant was safe.

We feel there was a significant training burden that NRC has got to enter into in training their people on how to ask the right questions to be supportive of their role to be sure the Licensee is doing the right things to protect the plant and at the same time the Licensee has to be cautioned in not speculating or trying to put together a story which seems logical to them if they don't have any of the facts.

In fact, in this particular case, what was communicated looked like an ATWAS, it sounded like an ATWAS.

MR. REED: I would like to make a point here. When I was on the receiving end of the red phone installation at its outset -- and the rules of the red phone, I never liked this reporting as soon as possible or right close behind an event.

Hell, in the shuttle incident nobody is reporting; in FAA incidents nobody is really reporting, and I objected to that "as soon as possible" phrase. I still object to it. I think it diverts people from their safety activities and I really don't think the NRC red phone contributes one hell of a lot.

If there is a need, will be a need, in that there will be any contributory significance from the NRC being told immediately or as soon as possible, fine and dandy. But I think we ought to find a way to differentiate

so we don't divert these people from real safety activities.

I think what you have here is a very good example that should be studied in depth for its impact, whether or not the phraseology and the red phone should be changed.

MR. MARTIN: We would not disagree with you in the way it was used in this case. It did not contribute positively to the response. It did distract the people. In fact, the ringing of the NS phone right at time zero, the shift supervisor properly made sure his plant got scrammed and the people responded before he picked it up. But his information even then was not firm and so, his response at that point, he couldn't really give a good story. It would have been much better if he had 15 or 20 minutes to digest it and had somebody else make that communication.

MR. EBERSOLE: You really need another bullet up there about the NRC. Well, you have, "communications not effective."

MR. MARTIN: There are findings which we'll get to. The finding will bring this out.

MR. MICHELSON: The phone wasn't supposed to be used to begin with. At that point in time there was some kind of glitch that caused it to ring, so I think this was an exception. You wouldn't want to throw the red phone out

just because it happened in this case to ring.

MR. CATTON: Are there any examples of where it was helpful?

MR. MICHELSON: I'm sure it got all screwed up in the beginning. The first thing that happens when you scram your reactor, for the red phone to ring, it gets everybody off on the wrong foot.

MR. REED: I'll have to look for a bypass.

MR. KERR: Let me ask. You said, I believe, the NRC needed to understand what is going on in order to try to do it, whether the operator was doing the right thing.

Suppose you decided the operator was not doing the right thing. What would NRC do?

MR. MARTIN: Make recommendations. We do not have authority at that point to do anything else.

MR. KERR: What does making recommendations imply to you?

MR. MARTIN: Have you considered the steam generator blowdown? Has it been shut?

MR. REED: That would be an obvious recommendation from 1000 miles away?

MR. MARTIN: That's true.

MR. REED: Frankly, if I was 1000 miles away and I was the dog of the NRC, I wouldn't dare to make any recommendations to the operating staff with respect to

anything concrete to do, except, maybe, evacuate the population.

MR. MICHELSON: I thought that was what the red phone was for, so the NRC would have some idea.

MR. MARTIN: I happen to agree with you, it's better to have NRC on-site. That's why they would move them to the site if the plant was in an unsafe condition. How do you know it's in an unsafe condition --

MR. KERR: It's really better to have the NRC people there where they can tell the operational crew in person what they should be doing?

MR. MARTIN: Again, that's recommendations. No, sir, correct.

(Discussion off the record.)

MR. MARTIN: Let's go forward now. The equipment problems, the power supply cable appears to be a ground fault. There was two places where the cable was ruptured. They are located in cable trays under a feedwater line with a flange. The flange shows evidence of long-term water leakage in that area. It is that there may have been some connection between this water leakage and the ground fault. The analysis is ongoing. We don't know any more about it.

The flash evaporator failure we have already talked about.

The safety injection annunciator, it was the first spurious alarm. We found now it will always alarm on loss of power whether you have a safety injection or not and we deem that a design deficiency.

The safeguard load sequencing system also indicated a safety injection actuation. To date we have not been able to determine why that occurred and the analysis is ongoing.

So you had two indications of safety injection, the operator reviewed those two, reviewed plant conditions, reviewed containment conditions, determined that a safety injection was not warranted and verified that the safety injection loads had not started.

MR. MICHELSON: By that last statement do you mean they verified that the valve realignments hadn't occurred and so forth?

MR. MARTIN: And the pump hadn't started in that mode.

MR. MICHELSON: These would have been the feedwater pumps, wouldn't they?

MR. MARTIN: That's correct. But even later on, if he thought there was a safety injection, his diesels were operating. They were sitting there ready to be loaded. All they had to do was to cause the bus to be stripped, to load those buses, and then to load these things on.

MR. MICHELSON: The bus was already stripped, wasn't it?

MR. MARTIN: No. Just deenergized at this point.

MR. MICHELSON: Didn't that strip the bus?

MR. CHIRAMAL: Yes. It would strip the bus.

MR. MARTIN: Okay. But all he had to do was close in the diesels and start these, but he saw there was no need to do that at this point.

Okay, the loss of voltage --

MR. MICHELSON: He was not yet reconnected?

MR. MARTIN: No. This is in the four-minute period.

MR. MICHELSON: This was the time he was in the total blackout, diesels were running but he decided not to even reconnect his emergency -- normal lighting?

MR. MARTIN: He had emergency lighting, but normal lighting, you are correct. He didn't even do that because their procedures and training emphasizes that off-site is the preferred source.

MR. MICHELSON: He had off-site. He knew that, I hope?

MR. MARTIN: And therefore they were waiting for the auto transfer scheme to complete, which sets up the conditions necessary to repower the plant, shutting one breaker in the switchyard.

MR. MICHELSON: That is all automatic, isn't it?

MR. MARTIN: It takes approximately two to four minutes for that scheme to complete. But then there is one manual operation at the end.

MR. MICHELSON: Let me make sure. Automatically it takes three to four minutes for the breakers to realign themselves?

MR. MARTIN: Because what you have to do is decay the voltage on the bus at the discharge of the generator to the point that you can open that no load disconnect.

MR. MICHELSON: Okay. He was waiting for his break shift to disconnect. Thank you.

MR. EBERSOLE: The coastdown must take two or three seconds.

MR. MICHELSON: He said he can't reconnect them until he --

MR. MARTIN: If you can't feed anything the voltage will stay up.

MR. EBERSOLE: Doesn't it go to a very low level in a few seconds?

MR. MARTIN: No, the generator is still rotating at 3600 rpms. There's always some residual and the voltage will stay up.

MR. EBERSOLE: That high?

MR. MARTIN: Yes.

MR. EBERSOLE: That last manual action, you are telling me the diesel does not automatically connect?

MR. MARTIN: Unless you have a safety injection in coincidence with the loss of power.

MR. EBERSOLE: Why didn't it come on, then, within three and four?

MR. MARTIN: Because there was no safety injection. These were erroneous indications.

MR. EBERSOLE: Oh, they weren't authentic.

MR. MICHELSON: People that don't have generator breakers, then, can never connect their diesels onto emergency buses for three or four minutes? Is that right?

MR. MARTIN: No, no, no. Let's get the electrical schematic back on here.

MR. MICHELSON: This is not the only plant in the country.

MR. EBERSOLE: I find it hard to believe the residual can be so high.

MR. MARTIN: You have a generator coasting down, you have residual magnetism and no loads, no current that gives you the IR drop, to give you the lower voltages, so this voltage coasts down very slowly. You are sensing the voltage on this bus.

Now, this breaker is open, that breaker is open.

So, it's not feeding anything. The diesels could be closed onto this because it is open and this is open. (Indicating.)

So this is basically a dead bull with a diesel sitting here operating, ready to be loaded. All you have to do is close that breaker. Over here, closing the breaker and you have reenergized the buses.

MR. MICHELSON: They just don't have that feature?

MR. MARTIN: They don't have it today.

MR. EBERSOLE: The MOV that senses the slowly decaying voltage and doesn't clear until it's visually zero?

MR. MARTIN: What is the voltage?

MR. CHIRAMAL: 40 percent. Then it will open.

MR. EBERSOLE: Then it will open.

MR. MARTIN: But it takes time. This is a motor-operated thing, so it drives open and how long it takes to drive open, we have not tested that because with -- we had one diesel down during the refueling outage that was being disassembled and worked on, we had an auxiliary transformer that was out because of this current fault, so this was the only reliable off-site source. We didn't want to play around with this and try to find out what happened until they reestablished these additional power sources, so we basically said: Let's leave that for future analysis.

MR. MICHELSON: The operator, then, could have

closed the diesel if he wanted to. He just elected not to?

MR. MARTIN: That's correct.

MR. MICHELSON: Some reason why?

MR. MARTIN: The training and procedures emphasize that off-site is the preferred source if it's available?

MR. MICHELSON: Even if you are sitting in a blackout. How black is the control room on emergency lighting?

MR. KENNEDY: Their emergency lighting is nearly the same as their normal lighting.

MR. MICHELSON: So they weren't really in the dark then. Thank you.

MR. MARTIN: Let's go on.

(Slide.)

We talked about the computer, the turbine rupture discs; four of the eight failed. That's expected on a loss of power event.

Emergency notification system, the spurious rings, we talked about that. So far we cannot reproduce that.

RCP thrust bearing, there was a high temperature alarm. It has now been determined it is a failed detector. Then we started getting into the check valve. The studies were stretched and you had the body to bonnet leak that was

as a result of the water hammer.

(Slide.)

These check valves failed at the beginning of the event. This first one, the nut was missing that connects the disc to the hinge arm and the disc was separated from the hinge arm and in fact laying in the bottom of the valve.

The second one, same condition.

The third one, the nut was loose and stuck open. As a result, when the ditch approached the seating surface it gouged into it and was held in the open position.

This one is in the same condition.

MR. EBERSOLE: Let me ask you a question about the check valve. There's a general design rationale that if you put one or two or three or n devices in a series which are presumably redundant with each other, you don't know what you have until the last one fails, unless you monitor the progress failures of the others? Are there any actions to do that?

MR. MARTIN: They are part of the IST program. All these valves are. But the failure mechanism -- one of the points we are going to make, these valves will fail within less than a year's time. All of them.

MR. EBERSOLE: You told me they had a check on these in November. Was that the last valve that was

working that caused it to pass successfully?

MR. MARTIN: Was that the last --

MR. EBERSOLE: Or would you know? Suppose the last check valve in the line worked and you never did know what the rest of them were doing?

MR. MARTIN: Each check valve is tested individually.

MR. EBERSOLE: Oh, is that right?

MR. MARTIN: And some of them were tested as late as February of '85.

MR. EBERSOLE: How did they check it individually? Are they artificially blocked open?

MR. MARTIN: The ones that go to the steam generator, what they do is they use the head of water in the steam generator, which only is about 10 feet, about 5 psi. They shut the upstream motor-operated valve, they open a drain just downstream of that motor-operated valve, let the line drain and then if the leakage goes to zero or very low leakage, they say that check valve is performing its safety function.

MR. EBERSOLE: That's not a dynamic test. That's just a static test to see that it seats.

MR. MARTIN: Demonstrates it can perform its safety function, that being, it can throttle flow. Not necessarily leak tight. The C test for the IST requires

for check valves that they be able to throttle and essentially provide a differential pressure.

MR. MICHELSON: These are isolation valves in some cases, of course.

MR. MARTIN: They are not containment isolation valves.

MR. MICHELSON: The feedwater checks -- if they aren't then which ones are they?

MR. MARTIN: Appendix J, they are not required to be containment isolation valves.

MR. MICHELSON: Which ones are?

MR. MARTIN: Feedwater does not require it. It is seismic. Up to those check valves it's a seismic system because of the AFW system over there.

MR. MICHELSON: That's fine. But upstream of the check valves it's not seismic. I was just inquiring where are the isolation valves for the line, because that's the first valve coming out of the system?

MR. MARTIN: The safety-related piping goes all the way up to those MOVs, the matter operated valve that was shut terminated this particular transient. All those are safety-related valves. All of those are subject to the IST program.

MR. MICHELSON: You are avoiding my question. My question is which, by identity, are the so-called

containment isolation valves?

MR. MARTIN: There are no containment isolation valves on feedwater. This is a PWR. By appendix J it is not required.

MR. MICHELSON: Okay.

MR. REED: Back to the check valves. Just a minute. Are you telling me that those check valves were either tested or maintained within the last year?

MR. MARTIN: Yes, sir.

MR. REED: And this event of failure of these check valves took place in the last year? This is an old plant that has been running for 20 years. Are these the same check valves that were there originally?

MR. MARTIN: Some of them have failed before, similar failure, and have been repaired.

MR. REED: And now all of a sudden five have failed. It will be interesting to look at the maintenance history on these valves and find out whether the people maintaining them were aware and were alert to a generic design deficiency?

MR. MARTIN: I think we are going to get to that. That's our major finding, by the way. But let us talk about that when we arrive at it and I know the Licensee has a specific presentation just about those check vaives.

Okay. The flow control valve, because the

upstream or downstream check valve was laying in the bottom of its body -- the flow control valve took a shot and because the whole line moved laterally -- the actuator sits on a very tall yoke and is a very massive unit; as a result, the inertia and bending stress caused the yoke to break and the stem to be bent.

MR. MICHELSON: Was the stem bent inside the valve or outside the valve?

MR. MARTIN: I don't remember. Licensee, can you answer that? Where was the bend?

MR. RAINSBERRY: I don't remember either.

MR. MICHELSON: What type of valve is it?

MR. SERKIZ: Carl, as I recall, when I looked at the components, if there was a bend it would be external to the body because it goes up and then your unit is up above.

MR. MICHELSON: This is a hydraulic-operated valve?

MR. MARTIN: No. This one is air-operated.

MR. MICHELSON: What kind of valve? Is it gate? Y?

MR. MARTIN: It has the cage in it. It has two discs. They would be globe valves. This is a flow control valve. It's double disc --

MR. SERKIZ: A fisher valve and then it's a different machine.

MR. MICHELSON: You mean it's not a plug valve?

MR. SERKIZ: They have the two plugs. They come in place. It's the flow control valve.

MR. MARTIN: It looks like a dumbbell.

MR. MICHELSON: What position was it in for the water hammer?

MR. SERKIZ: Full closed position, because they would have, at that time, through procedures, closed the motor-operated and all the other valves.

MR. MICHELSON: So this was thought at that time to be in the fully closed position?

MR. SERKIZ: If you ask now what fully closed means in terms of actual closure -- it's fully closed.

MP. MICHELSON: There is no damage to that valve other than bending the stem?

MR. SERKIZ: Yes. The stem was bent when it came up through the packing and it would come out through the pneumatic driver.

MR. MICHELSON: Broke the yoke, but no damage to the plug itself or gate or whatever you want to call it?

MR. SERKIZ: If you bear with me a second, we have a picture in here. That picture is in your report, Carl.

MR. MICHELSON: It is? I must have missed it. Do you recall what figures? This must be the photograph,

then. I thought it was a diagram. You couldn't tell anything with these.

MR. SERKIZ: If you look at figure 6.38 and 6.39. On page 6.45. 6.38.

MR. MICHELSON: That's one of the photographs. You can't tell a thing from that.

Oh. Yes. There's a photograph. Go ahead. That takes care of my question. Thank you.

MR. MARTIN: B steam generator feedwater line had a crack in it. It is bent, dented. We believe that is all associated with the water hammer. And licensee was continuing his evaluation there.

The feedwater line and supports and snubbers, a number of them were damaged again, water hammer, and licensee's evaluation is ongoing.

The auxiliary feedwater line supports, there was some displacement of the line but we found no damage there.

Containment sphere, there were some small, crack-like indications in a saddle that went around both the feedwater line and one of the safety injection lines. Since then the Licensee has done further evaluation there and I'm sure will be able to comment on those. And there was also a problem with the security access control system, where it had a failure, mal-operation, and the operators had procedures and keys and things like that that they were

ready to respond to such an event, and there was really no safety or safeguards interface problem. The operators, as a result of our previous actions and their previous actions, were ready for this event.

(Slide.)

MR. MICHELSON: One of the things I didn't find in the report, unless I missed it, and that is the piping configuration in the immediate vicinity of the feedwater check valves.

In other words, how close was the control valve to the check valve in terms of potential turbulence generation and also in terms of the water hammer; I think it's a very important matter to know exactly where these busted valves are relative to the other obstructions in the system.

MR. MARTIN: They are very close to each other.

MR. MICHELSON: Did I miss it? Is it in the report?

MR. MARTIN: If it's not, we have it as backup.

MR. MICHELSON: I would like to receive a copy --

MR. SERKIZ: 6.30 in there will give you some idea. But the dimensions you are asking for, Carl, would have to come off a piping diagram.

MR. MICHELSON: Figure 6.30?

MR. SERKIZ: 6.30. But there's no dimensions.

If you are asking for the dimensions, I can get them to you.

MR. MICHELSON: Yes. That one didn't give me quite the help I needed, because I didn't know whether it was one foot or 10 feet or 100 feet or what?

MR. SERKIZ: In round terms the stations, if we are referring to figure 6.30, would extend about 15 feet.

MR. MICHELSON: There's 15 feet between the check valve and the flow control valve?

MR. SERKIZ: No, no. All the valves in 6.30 would be upstream from where this point stops from, FWS3.42, going back up to the motor-operated valve 20.

MR. KENNEDY: You may be able to see it by factoring in the identified valves in 6.32 and figure 6.33. You see how close they are.

MR. MARTIN: Do you have the drawing that shows the main steam isolation valve?

MR. MICHELSON: See, we didn't have photographs.

MR. SERKIZ: Carl, look on figure 6.33. That will give you a quick indication. 6.33.

MR. MICHELSON: Oh, yes, that's it. See, our photographs are all black. They Xerox.

MR. SERKIZ: You have a Xerox of a Xerox.

MR. MICHELSON: When can we get a copy of the NUREG, since that's really what he needed.

MR. LANNING: We had your name, I thought,

according to the standard distribution.

MR. MICHELSON: We got Xeroxes, that's all I got. The photographs were totally black in the Xerox. This is what I needed.

MR. SERKIZ: If you need the dimensions --

MR. MICHELSON: No. This is great.

MR. SERKIZ: As I was saying, 15, 10 feet.

MR. SAVIO: They are on their way. They haven't arrived yet.

MR. MICHELSON: This is what I needed. This would have done it. Thank you.

MR. EBERSOLE: Before you go into this, let me ask you if you can throw back 4.3, the main feed system which also shows the interfacing aux feed system? All I really want -- I thought it would be worthwhile -- is to look at the totality of check valve failures.

MR. MARTIN: Let's go back to 52?

MR. EBERSOLE: The main feed system which shows the point of insertion of aux feed. And then ask the question how many more check valves failures would have put us in real duress.

MR. MARTIN: You lost most all of them at this point.

MR. EBERSOLE: Let's go back to the nest of checks on the right there.

MR. MARTIN: This is a six-inch, a 10-inch and a 12-inch. This would have been sitting there shut anyway. This is the valve that they use, and these two are the ones they shut per procedure that isolated this.

MR. EBERSOLE: Hypothetically, this failure might involve fragments coming down into those valves and ruining them, okay?

MR. MARTIN: That's correct. But once --

MR. EBERSOLE: If I lost that whole set, lost that boiler.

MR. MARTIN: You have lost it as a unit.

MR. EBERSOLE: I'm talking about as a heat sink to get rid of decay heat. The other boilers are still functioning. I'm trying to get a notion of how many valve --

MR. MARTIN: Recognize we had all of them blowing down. You are right. If for some reason -- this is sitting shut, so even if a part comes back here, I won't bother this one.

MR. EBERSOLE: Until you open it. Well, it won't even come back.

MR. MARTIN: These two, the thing that started the refill and failed, it would be the shutting these two -- this check valve had already failed though, and was blowing back this way. The mechanism to cause the shattering of this did not occur until after these were shut.

MR. EBERSOLE: Yes. That was in fact what caused them to do it.

MR. MARTIN: Because it started the refilling and led ultimately to the water hammer.

MR. EBERSOLE: I'm just trying to find the residual competence to redecay heat via the secondaries. How much residual competence did you have? How many more check valve failures would have put me in real trouble?

MR. MARTIN: You basically have failed all the check valves except these little four-inch, which are in shut-off lines already. All the other check valves have failed.

MR. CATTON: All six of them?

MR. MARTIN: Only five. 1, 2, 3, 4, 5.

MR. EBERSOLE: So the whole active set of check valves went?

MR. MARTIN: Yes, sir.

MR. EBERSOLE: I'm having real trouble believing that this was a point in time where we found that they had all failed progressively prior to this time, but rather it was a point in time where we had some physical event.

MR. MARTIN: There's a unique thing that we haven't gotten to there. The plant, because of the two steam generator tube sleeving and plugging, et cetera, no longer -- can't go to full power any more. It's full power

is around 90 percent power.

It looks like at this point that these check valves are improperly sized, such that at the lower flow rates associated with its lower power, they sit down into the flow stream and licensee -- I don't want to get his thunder, but he's going to tell you some information why these failed very rapidly under this particular situation. So he thinks he has been able to demonstrate why, within less than one year, all these seemed to fail.

MR. CATTON: Flow vibration caused the nuts to loosen up?

MR. MARTIN: Yes.

MR. EBERSOLE: Suppose these valves remained open, and I was still able to -- not the steam driven but through the motor-driven pumps -- if I could drive primary water in through the -- sorry -- secondary water through the aux feed pumps, the motor-driven pumps, would it have gone to the boiler by virtue of gravity or whatever?

MR. MARTIN: No.

MR. EBERSOLE: It would have drained out to the low point?

MR. MARTIN: This is about 10 feet below the feed ring.

MR. EBERSOLE: So I have a dried up secondary if I had been unable to cope with these?

MR. MARTIN: If there was no way to shut off these paths, you are correct.

MR. EBERSOLE: This gets back then to the critical nature of the check valves and their dynamic performance, whether they shatter. I would think it might be very prudent to have motor-operated or other kinds of valves in front of these damn things to preclude the potential for -- you know, they can come close. Especially if you have a broken pipe down here, they can come shut with a crash.

MR. MARTIN: If you take that hypothesis, then these valves, which are manual valves which will ultimately be used in the event --

MR. EBERSOLE: If you can get this without having to kill yourself.

MR. MARTIN: But if these had not shut off successfully, then you would not have had the refilling and the water hammer. The fact that they shut off and are now in place as barriers now can't be compromised by pieces coming back, because there's no flow path here.

MR. EBERSOLE: Sure. If they were able to shut.

MR. MARTIN: That's right. So any scenario you try to use to get there, if you compromise these, then the water hammer will not destroy this station because you certainly have a tremendous attenuation of the pressure if

there's a free path through there.

As a result, then this line would probably be available, this manual valve would probably be available to shut.

MR. EBERSOLE: If you can physically get near it?

MR. MARTIN: Yes, sir.

MR. REED: I noticed we used the word shatter here, you used it, Jesse used it. These valves came apart. I am not sure how they were tank-welded or what. In my experience, I don't think I have ever seen a shattered check valve. I have seen a lot of them come apart.

MR. MARTIN: Although we don't know it's connected with the event, this valve, the four-inch, which took the brunt of the shock wave, its seat is just cracked like spiders. It's spiders all through the stellite seat there.

MR. REED: Did it shatter?

MR. MARTIN: In this case it didn't.

MR. EBERSOLE: Isn't it a fact of life that the dynamic duty on a check valve is rarely if ever, certainly sporadically, checked by opening the pipe below it? Nobody looks at that dynamic need performance as a routine design consideration, do they?

MR. MARTIN: I can't answer that.

MR. EBERSOLE: Only a few people do. It's not a

generic requirement that you look at the dynamics of closure against an upstream failure of the pipe.

MR. MARTIN: Can you answer that?

MR. LANNING: That's true. There's no such test that includes consideration of a pipe rupture upstream.

MR. EBERSOLE: Even for the boiler that handles primary fluid?

MR. LANNING: Yes.

MR. EBERSOLE: I mentioned studies to a certain consultant and they begin to look dismal and the unfortunate result of that was to cut off viewing down the dismal road. I think that's a sorry state of affairs; when you start getting poor results in your analysis, you turn off your analysis, but nevertheless, that's what sometimes happens. I think now we have the trigger to do some of this work.

Go ahead.

MR. MARTIN: We believe the event was significant because all in-plant AC power was lost for four minutes, all steam generator feedwater was lost for three minutes, a severe water hammer was experienced in the feedwater system that caused a leak, damaged the plant equipment and challenged the integrity of the ultimate heat sink, all indicated steam generator water levels dropped and the reactor coolant system experienced an acceptable

but unnecessary cooldown transient.

(Slide.)

From here on we go into our findings. The primary cause of the water hammer was the failure of the multiple check valves. The failure of the five check valves in the feedwater system provided a mechanism for a potential common mode failure of the heat sink, that the long horizontal runs of the feedwater piping with the potential for voiding are particularly susceptible to destructive steam concentration-induced water hammers.

It turns out 9B feedwater line is the longest one. It runs about 202 feet -- 220, I guess, and it's perfectly horizontal the whole length.

(Slide.)

MR. MICHELSON: Have you thought about why the check valve in the bypass line was the one to have lifted its bonnet instead of the flow control valve in the main line? Since the check valve in the main line was already open and apparently laying in the bottom or something, why didn't the bonnet on the big line lift instead of on the little line?

MR. MARTIN: Carl, it would be difficult to say because we don't know for a fact that the upstream valves were fully shut. If they are not fully shut you attenuate the wave.

MR. MICHELSON: That's right. You know if the bypass was fully shut, I guess, but you are not sure if the main flow control valve was?

MR. MARTIN: As a matter of fact, we don't know if the main flow was except for the check valve. The indication says they were shut, but there's too many parameters we don't have knowledge of.

MR. MICHELSON: A small leak won't make any difference. The check valves themselves I think have little holes in them purposely.

MR. LANNING: Not these.

MR. MICHELSON: Not these?

MR. MARTIN: The ones down by the feed pumps do but these up here do not.

MR. MICHELSON: But in this case you knew the check valve probably had already lost its disc; is that right?

MR. MARTIN: Yes.

MR. MICHELSON: On the main line?

MR. MARTIN: Because of the denting.

MR. MICHELSON: And yet the only damage to the flow control valve seemed to be operator damage due to a rapid acceleration, I guess, bending the stem and breaking the yoke.

MR. MARTIN: That's what it appears to be.

MR. MICHELSON: Yet no damage to the gate. Of course it depends on the design of the plug or gate or whatever it has got as to whether it would have -- but the bonnet certainly saw a large pressure wave I would have thought, since it's seeing the reflected more so than the little bypass where it has to go through a little elbow and so forth to get to it. It doesn't make sense that the main line didn't see the big damage instead of the bypass line.

MR. EBERSOLE: May I ask, what capability if any has this plant to feed coolant --

MR. MICHELSON: Let me get an answer to my comment or question first. Did you think about it? Has anybody looked at why the bonnet on the bypass lifted instead of the bonnet on the main line?

MR. SERKIZ: Carl, I can't give you an exact answer because we don't have a detailed stress analysis on all of them. Structurally, the bigger valves are structurally more capable of taking a certain psi loading.

MR. MICHELSON: There's a lot bigger areas, too.

MR. SERKIZ: All that we know after the fact is that the four-inch valve, the bolts plastically yielded. As soon as that opened and started to reduce the water hammer, that acts as a safety, in effect.

MR. MICHELSON: You can see my question, though. My question is why did the little one on the bypass lift

instead of the bonnet on the main line?

MR. SERKIZ: On the bigger one the bolts are bigger.

MR. MICHELSON: But it didn't seem -- theoretically, why the shock would have propagated itself at that point --

MR. SERKIZ: It's at the same point for all practical purposes.

MR. MARTIN: Carl's point is when you go around that 90 degrees you lose pressure.

MR. MICHELSON: It's 90 degrees away from where we think the water hammer occurred. There must have been a great deal of attenuation through the elbow, but that's where the shock seemed to have found a weak point?

MR. CATTON: Was it on the big pipe or the little one?

MR. MICHELSON: On the big one.

MR. MARTIN: It propagates all through.

MR. CATTON: I understand it propagates, but where did it initially take place?

MR. MARTIN: Near the steam generator in the horizontal line.

MR. CATTON: That's in the big one?

MR. MARTIN: Yes.

MR. SERKIZ: In the last horizontal run before

taking the vertical upturn into the steam generator.

MR. MICHELSON: A long way from this little bypass line which takes off from the bypass line back to the valve.

MR. EBERSOLE: I would like to get to a real root issue here. This is an unprecedented failure as far as I know, all these coincident failures. I would like to loft us off to the Palo Verde case, and I ask the question for this reason. This plant, I think, at least it has some PORVs, and presumably may have some potential for feed/bleed if Palo Verde or its kind do not. Are they standing in the presence of this sort of check valve failure and therefore up the creek for sure? That's why I asked the question, can this plant feed/bleed, because I know the Palo Verde plants cannot.

MR. KENNEDY: The procedures do have instructions for feed/bleed.

MR. EBERSOLE: They can feed and bleed. On the other hand, I must now say in the absence of another situation, Palo Verde may have a network of valves precisely like this, and that has not been introduced into the PRA studies or aux feed failures. So let's inject into those studies the result of this plant performance.

MR. MARTIN: Do you have any comment on that, Wayne?

MR. LANNING: No.

MR. KERR: Let's not be guilty of asking for information which the staff doesn't have.

MR. EBERSOLE: I'm saying let's inject the findings here into the Palo Verde study. We've got to take this result and inject it into the current -- were is it, 10 to the minus 5 failure rate of aux feed?

MR. KERR: That's a goal.

MR. CATTON: This one has two CE plants. Wouldn't they be the first to carry this over to their Units 2 and 3?

MR. EBERSOLE: Here we have a new input to aux feed failure, which, as far I know, is not present in the plants that have defended the plants without feed/bleed.

MR. KERR: Water hammer is not unknown previously.

MR. EBERSOLE: But its consequences in this failure haven't been defined.

MR. KERR: I have heard discussions about the consequences of water hammer since I have been on this committee.

MR. EBERSOLE: They have not been inserted into Palo Verde.

MR. CATTON: They have been considered resolved?

MR. MICHELSON: Yes. They have been resolved.

MR. MARTIN: The timing of the five check valve failures could not be ascertained with certainty; however, the team concluded that all check valves had failed prior to the event because the missing parts of the valves were not found in the inspected feedwater piping after the event, which would have been upstream of the valves.

MR. MICHELSON: In that regard, has the utility looked at other check valves, you know, that were not thought to have failed? Did they look at some of them anyway to see their condition?

MR. MARTIN: In this plant there were 13 check valves of the same design. They looked at all but one before we had left and that one that was left was in the turbine plant cooling water system.

My understanding is they are looking at other check valves, but I don't know the details of their examination.

MR. MICHELSON: Have they found any indications of problems with these valves other than the ones that failed?

MR. MARTIN: My understanding is they have not, but we'll be having specification on the check valves.

MR. KERR: Number 6, the second sentence seems like something of a non sequitur. The first sentence refers to the testing not being able to tell whether check

valves are closed. The second sentence, although it has a "thus," seems to refer to the inability of testing to determine whether the valve is damaged or not, not whether it's closed.

Is there a sentence left out or something?

MR. MARTIN: Well, let me see.

What it's basically saying is we don't have confidence in the surveillance procedure as it is written to tell you that your check valves are failing in this mode.

MR. KERR: But the first sentence says, "determining whether check valves are closed." Now, if it meant to say "determine whether check valves are deteriorating," then I can understand the two sentences.

MR. MARTIN: Okay. I understand what you are saying. We don't even believe it could demonstrate adequately that the check valves are closed.

MR. KERR: So the "thus" ought to be out of there and that's a second thought not related to the first, I assume?

MR. MARTIN: Okay. That's part of it. The trouble is the results of the test as designed are very subjective. Basically you are looking at a one-inch line and looking at the flow coming out of that line that has maybe a 10-pound differential pressure -- 10 pound? Five-pound differential pressure driving it through --

MR. KERR: I don't disagree with that. It just seems to me those are two separate thoughts. I was trying to understand whether I was missing something. I think you have now convinced mere that there are really two separate thoughts. One has to do with testing, find out whether the check valves are closed; the other has to do with testing, find out whether they are deteriorating.

MR. MARTIN: That's the last thing here, I think, what we are talking about.

The first is the test as designed looks for flow coming out of a little hose, and saying that that flow is representative of throttling or not, and you only have 5 psi in the water through this network of pipes, network of valves, the little drain valves, the long holes. And you look at that and say, aha, that means it's closed.

Is it 1 DP34679? 10 GPM? No mesh.

MR. KERR: I'm convinced.

MR. MARTIN: Last sentence here, further, even if they demonstrate that they are closed, it doesn't demonstrate it's going to be closed the next time because you may just be lucky this time, the seat hits and bounces off and then shuts. Even though the nut is loose, maybe even the nut is off. It doesn't really matter.

(Slide.)

At the time we completed our investigation the

in-service testings program had still not been approved by the NRC. It had been revised in its entirety in 1984 and part of the problem with resolving that was both SCE and NRC's responsibility.

We then looked at the resolution of the water hammer unresolved safety issue. We found that it did not specifically address the prevention and mitigation of the consequences of condensation-induced water hammers in feedwater piping upstream of the feed ring. In our interviews of NRC Staff we determined that the resolution of the water hammer issue failed to develop a citable reference, a decision or discussion that provided a basis for excluding further consideration of feedwater piping water hammer. However, we did note in the regulatory analysis that the Staff acknowledged that the elimination of water hammers was not feasible; that the frequency of water hammers had been substantially reduced by changes in design and operation; and that studies of water hammer had revealed a significant lesser safety concern than previously hypothesized.

It appeared to us that further consideration of water hammer due to main feedwater line voiding was not pursued due to a lack of reported occurrence in NRC U.S. plants.

MR. EBERSOLE: That's right. We always wait for

something to happen.

(Slide.)

MR. CATTON: What is done differently in the check valve testing for the primary system to RHR?

MR. MARTIN: We did not look at those.

MR. CATTON: It seems to me that you would test check valves the same way throughout a plant. If those check valves are tested similarly to these you would come to the same conclusions if they are not tested?

MR. MARTIN: Licensee even recognized some of the deficiencies in their test procedure and had revised test procedure even before this event so that the February tests that were performed on the check valves near the steam generators used the plant in mode 3 with a 700-pound differential. Now when you've got an open hose and 700 pounds, if you can't tell the difference whether it's open or shut -- that's no longer subjective.

MR. KERR: Does one have to use check valves?

MR. MARTIN: Instead of a stop valve of some type?

MR. KERR: A positive action valve.

MR. EBERSOLE: If you don't the reverse pressure will get to the low-pressure components so quick.

MR. KERR: You just use an ordinary valve in the thing.

MR. MICHELSON: Not fast enough.

MR. KERR: In the first place, some of the fastness that we require comes out of these design basis accident analyses that we do which are unrealistic.

MR. MICHELSON: No, no, for the overpressure protection they are code requirements.

MR. KERR: If you are telling me that the things don't work --

MR. MICHELSON: Then you've got to fix them.

MR. KERR: But can you?

MR. EBERSOLE: Suppose you don't have a check valve and the pump trips?

MR. KERR: You mean somehow the nuclear industry has gotten a lot of defective check valves and really if they got the right valves we wouldn't have this problem?

MR. MICHELSON: No, if you have misapplications such as downstream turbulence -- in other words, by putting a check valve very close to a flow control valve with a lot of downstream turbulence you are going to expect the check valve to flutter, and if it flutters it's going to fret and wear. So you have to be careful to put the valves in that will take that kind of condition.

There have been cases where the stake nuts have even become unstaked, in sufficiently violent conditions.

MR. KERR: The answer to my question is you need

to have check valves?

MR. EBERSOLE: The alternative would be an extremely fast valve driven by a hydraulic tube or cylinder, to reduce the closing times. Check valves which are faster than any others.

MR. REED: If you'll think back to the status of your subcommittee, I filed five to 10 problem areas and one of them was valves. We have a very active committee under Mr. Michelson, who is looking at the fragmented industry of valve business and to the -- not upgraded to nuclear grade, really.

MR. KERR: The experts tell me we have to have check valves. That's why I asked.

MR. MICHELSON: In these particular cases the check valve is the logical choice.

MR. EBERSOLE: Is there any particular reason? If you go, theoretically there's no particular reason that you couldn't drive a valve, disc, closed by means other than reverse flow, but it would have to be an extremely high capacity, high-torque machine.

MR. KERR: Main stream isolation valves are extremely rapid, aren't they?

MR. EBERSOLE: They close by virtue of reverse flow.

MR. MICHELSON: There are other types that are a

little less susceptible to this problem, but not --

MR. KERR: In any event, these valves aren't going to solve these problems.

MR. REED: He's going to solve it right away.

MR. EBERSOLE: The consequences of not having rapid closure would be pressurization of the downstream components quickly. You'd blow the pump casing, low pressure -- it gets back into the suction side so fast. So you have to move fast.

MR. MARTIN: Okay. One of our concerns was when we looked at the J tube fix for the feedwater ring water hammer, we noted that, whether it said it therein or not, it relied heavily on the fact that the check valves held because the J tubes were really designed to prevent draindown of the feed ring, and if you got the check valves on the inlet to those feed rings unseated, then the J tubes are not going to do anything for you.

We looked at the root cause of the phase-to-phase fault. The loss of power was due to the phase-to-phase fault. I don't think any more needs to be said there.

We also noted that the plant was designed to experience an extended loss of in-plant AC power, based upon the lack of an automatic loading of the diesels.

We further noted that the procedures on loss of AC power lacked guidance on how long the operators could

attempt to restore power from an off-site source before the diesel generator should be loaded. And, further, how long the diesel generators can run unloaded without overheating if their AC-powered fans remain deenergized. This caution had been in previous procedures but it had somehow gotten dropped.

(Slide.)

We noted the station loss of voltage auto transfer scheme for establishing the delayed access did not function as designed and they are evaluating that.

We noted that there were a number of spurious indications of safety injection, that the operators did the right thing. However, we felt that annunciation of safety injection when it is really not warranted challenges the operators, causes additional concerns, and we didn't feel that was appropriate. The operating staff, with the concurrence of management, did follow appropriate procedures when troubleshooting the electric ground. However, their actions were unnecessarily -- they unnecessarily delayed entry into the technical specification action statement requirements that could require plant shutdown.

MR. KERR: Excuse me. You read "did." That says "did not." Which is it, "did not follow appropriate procedures"?

MR. MARTIN: You are correct. Did not. They had a procedure, and if they had had followed it step by step it would have taken them into action statement. Every time they got to a statement that would have taken them to action statement they looked at what else could we do before we enter that action statement to remove other causes? And they did that three times during this event.

MR. KERR: Is that illegal or improper?

MR. MARTIN: It's not illegal. It's a concern to us in that had they done those things they would have very quickly defined where the problem was and, we hope, they would have carried through by deenergizing the line which ultimately failed. They had time to do it. Because of the way they did their testing, they actually introduced additional stress on the line that failed because it was -- we had a delta with no ground on it except this ground which had developed on the cable.

They paralleled that system with a fault on it to a grounded wire. That generates circulating currents through the degrading resistance of the cable and may have contributed to early failure. The things they did were not discussed in the procedure. And, as we went through the procedure we said: Why did you stop here?

The next thing, you had done everything necessary, you reduced power, you had taken off components.

All you had to do was turn the little switch. Why did you not go the next step?

And the answer we got almost unilaterally was well, that would have taken us into an action statement and there were other things we could do.

MR. KERR: Why didn't they want to go into an action statement?

MR. EBERSOLE: Shut them down.

MR. MARTIN: That's subjective. I can't answer the question. They never answered that.

MR. KERR: It seems to me you ought to look into that, because apparently that was a contributor to the situation, and I would think one would want to know why they were reluctant to go into a action statement.

MR. EBERSOLE: Wasn't it that they had a short time before they'd have to shut down?

MR. MARTIN: That's right. But -- this was a troubleshooting activity. We allow people to enter that for surveillance, for troubleshooting -- these are allowed and reasonable means for going into action statements. Our concern was, why didn't you take that? Your logic was wrong, is what we were communicating to them. If the concern is the ground is there you are going to have to shut down, you are going to have to shut down anyway if the ground is there. Therefore, it's unreasonable to go these

extra steps.

MR. KERR: I don't disagree. At least I don't hear anything with which I would disagree. But there seems to be a reluctance on the part of this group to go into an action statement.

You have pointed out one situation in which they would have been much better off had they gone into an action statement, presumably. From a number of viewpoints.

If I were you I would want to find out if this was just typical of this one licensee or is there some widespread reluctance to go into action statements?

MR. MARTIN: You are asking for a generic response and I can't give that. Jack, can you?

MR. HELTMAS: That's part of the sequence of training procedures that they have --

MR. KERR: I'm not talking about training and procedures. I'm talking about an attitude. By all means, we want to avoid going into an action statement. Why? Because it, apparently, contributed, at least in your view, to the situation being much worse than it might otherwise have been.

MR. EBERSOLE: It sets them to a wind down for shutdown; isn't it?

MR. MARTIN: If they found a problem there. But if they found a problem there they'd have to shut down anyway.

I agree that the procedure could have been written better so as to have allowed them to do other things, safe things to check that the procedure didn't address. But there was no liability in following the procedure and that was our concern. Why did you take these unsafe steps when you didn't have to?

MR. REED: I'm concerned about this action statement. In fact, the way I visualize it, if these people had have gone into an action statement, this incident might not have happened and you might never have discovered the five check valves that were in pieces. This is an attitude that bothers me because I hear all the time that we want to prevent scrams or trips on reactors. Many times trips on reactors disclose problems, and I don't think we have evolved in the nuclear business yet where we want to avoid things happening. We should still be discovering. I'm very happy that the guy did what he did because that brought about an electrical collapse which brought about a disclosure of the real root issue.

MR. MARTIN: Mr. Reed, they would have found these problems in their later in-service testing, which supposedly is done on a quarterly basis, if they get around to it.

MR. REED: Is it a disassembly, in-service inspection?

MR. MARTIN: When the disc is laying in the bottom of the check valve it is impossible for it to develop any DP.

MR. REED: You are saying they would have found it some day?

MR. MARTIN: They would have found all five of them?

MR. REED: On a 10-year program?

MR. MARTIN: They are on a quarter, every three months.

MR. REED: These valves are tested every three months?

MR. MARTIN: That's the description, if they get around to it.

MR. REED: You just said "if."

MR. MARTIN: They would get around to it in a refueling outage because there's enough time during a refueling outage to do these things. The refueling outage was scheduled November 30. Nine days later they would have gotten into a condition to find these.

MR. REED: Chronological things may have stacked up in favor of what you are saying, but quite frankly, I'm happy that the chasing of the ground was the way that it was and that we disclosed another problem in valves, and I hope that our valve committee will cause a great deal of

pressure to do something about the industry.

MR. EBERSOLE: Let me ask you how much longer your presentation is? I have another meeting here.

MR. MICHELSON: Could you clarify a point on the diesel engines? You made a point, is it correct to assume that these are air-cooled diesel engines?

MR. MARTIN: They are water-cooled, which goes to a radiator. The radiator is in the overhead. You can have convection fueling that lasts about 39 minutes.

(Slide.)

MR. MICHELSON: How long can they run without building or room ventilation?

MR. MARTIN: Basically this is open screen to let air come in and go up through the radiators. They have fans that are AC-operated. You can operate unloaded for about 39 minutes before you need to have these fans turned off.

MR. MICHELSON: That's the only dependency on off-site AC power?

MR. EBERSOLE: When that temperature is exceeded are there loud alarms and annunciators?

MR. MARTIN: There are alarms. What the actual set one is I don't know, but all you have to do is put the diesels on the buses and they would have come on automatically.

MR. EBERSOLE: You can kill the diesels by ignoring them?

MR. MARTIN: Yes. Once the electrical ground was locked on feeder from the auxiliary transformer C to bus 1C, the operators did not aggressively pursue isolating the auxillary transformer. Instead they opted to leave the transformer energized while technicians performed inspections that did not require the transformer to be energized. Our concern is they left themselves vulnerable while they performed inspections that didn't require that vulnerability.

(Slide.)

The operator actions after the transformer trip were consistent with their training. However, in the team's judgment, some operators lacked detailed plant knowledge and we list the areas.

(Slide.)

On occasion, some site personnel who generally evaluate plant data lack sufficiently inquiring attitude. As a result, certain significant indications of underlying reasons for system response or component performance were not detected until brought to the attention of SCE by the team. It appears that SCE's process for evaluating and following up events may not be sufficiently thorough and systematic to assure that failed components are detected

and adequately explained.

I have to caveat that somewhat. We were pushing them. Our only job was the investigation. They had preparation for the refueling outage and things of that nature. We may have been just a couple of steps ahead of them, but our perception was that they needed to beef up there event evaluation program, including, somehow, making sure that the people they select for that function are very inquiring and won't accept the easy answer.

The status of steam generator blowdown systems is not indicated in the control room. We talked about that.

During the loss of all in-plant AC power, sufficient information was available in the control room to enable the operators to follow their procedures and ensure plant safety. However, control room operators had failed to have the technical support center reset following the electrical ground troubleshooting activities. This failure disabled the computer's ability to record new plant data and thereby denied the operators access to pretrip and post-trip trends that would have assisted real time and post-event analysis and evaluation. Had the station blackout been of longer duration or involved additional complications, operator responses and the functions provided by the techni^cal support center could have been hampered by the lack of trend data.

Not only did we lose the computer but most of the recorders.

(Slide.)

Maintenance records are incomplete, difficult to locate and, when available, lack sufficient detail to determine what was done.

In particular, when we tried to follow what was done on the check valves in the past, the records were very bad.

The spurious ringing of the NRC red phone did cause some distraction of people and some confusion.

Here most of this is NRC problem. Communications between NRC and SCE were not effective because: the NRC duty officer was not knowledgeable about the unique design of the plant and therefore misinterpreted operator responses to questions; communications with the plant were initially limited because statements by plant operators incorrectly implied that sufficient personnel were not available to support the establishment of an open line; NRC asked leading questions and operators sometimes did not correct, and in some cases appeared to confirm, inaccurate information; NRC questions characteristically focused on detail rather than on the big picture; NRC cluttered the communications with repetitive discussions about the sequence of events, and we go on and on. The

problem is, we need training. We need to do a better job in our communications and these were points that we were making.

(Slide.)

There were two malfunctions of the automated security system; however, site personnel implemented appropriate procedures and it precluded a safety-safeguards interface problem and there was no significant release of radioactivity.

MR. MICHELSON: Before you get to the conclusion, let me ask a question on observations. Have you made any inspection of the steam generator itself?

MR. MARTIN: The Licensee has. They looked at the feed ring and found no problem there. I do not know the results down by the tube sheet. That was being done after our investigation. I'm sure the Licensee can speak to that.

MR. MICHELSON: Thank you.

MR. MARTIN: The most significant aspect of the event was the five safety-related feedwater system check valves degraded to the point of inoperability during a period of less than a year without detection and that their failure jeopardized the integrity of safety-related feedwater piping. The root cause of the failures have not been determined and are still being reviewed by SCE and its

contractors. Potential contributors include inadequate maintenance, inadequate in-service testing, inadequate design and inadequate consideration of effects of reduced power operations.

MR. MICHELSON: When did the reduced power operations start? What date?

MR. MARTIN: November of '84.

MR. CATTON: What was the percentage reduction in the flow-through of these check valves?

MR. MARTIN: Down to 90 percent, approximately.

MR. CATTON: They reduced it 10 percent and that 10 percent, they feel --

MR. MARTIN: It looks like also the selection of the valves was inappropriate. The Licensee will speak to that.

MR. MICHELSON: They had to throttle to reduce the 10 percent; the turbulence downstream of the throttle perhaps is the problem.

MR. CATTON: It depends on how far away the throttle is. I have trouble with that.

MR. MICHELSON: It isn't very far.

MR. MEDFORD: We believe the design of check valves was marginal. The operation at 90 percent would yield the inadequacy of the design. We have performed analyses, we have brought in experts and can show the

quantitative results in calculations.

MR. MARTIN: Talking about the contributors, we could not preclude maintenance because of the type of maintenance that was done and the records that were kept. In some cases, records that we did have didn't tell us what was done; in other cases, we just couldn't find the records of what was done.

The in service testing records for these valves were inconsistent. There were several records and they didn't agree with each other. We think that was due to administrative errors. The testing procedure was not rigorous. We believe that it was very subjective, in some cases. The test acceptance criteria was subjective. The testing frequency was open-ended and the test did not assure detection of the failure found.

Our point here on the IST is that if -- it's important to do these tests on a quarterly basis and if these things are subject to these types of failures then you are going to have to go out of your way to perform these tests at that frequency.

In fact, even though they are quarterly tests, some of these valves have not been tested for over -- just about a year.

The check valves and valves of similar design have a history of like failures. You can find that in the

literature. You can also find these valves, some of them had failed in a similar manner before at this plant. And reduced power operations at Unit 1 are now routine, and we talked about the thermohydraulic -- hydraulic-induced vibrations there.

MR. EBERSOLE: Is there any way to look through the valve body and see if it's fluttering? Like X-ray?

MR. MARTIN: The Licensee has used X-ray. It hasn't been very much use to him and I can't explain why. Possibly just because it's moving it doesn't give a good image.

MR. EBERSOLE: They have no need to go to a hospital. They have instruments there that will do it.

MR. CATTON: Why not just vibration measurements?

MR. EBERSOLE: Let's have a 10-minute break until 20 after and then we'll move on to the remainder of the presentation.

MR. KERR: Do we have to discover root causes or are we going to hear something that says here are the root causes, two or three?

MR. MICHELSON: What are the real root causes?

MR. KERR: Does that presentation indicate there were 20 root causes or the root causes are still undetermined?

MR. MARTIN: The root cause we believe is the

failure of the check valves. Why it failed, I'll leave that to Licensee because he's done more evaluation than I have.

MR. KERR: I thought the event was the failure of the check valves. If one was looking for root causes for that failure --

MR. MARTIN: What I'm telling you today, I cannot tell you what the failure was. The Licensee has more information.

MR. EBERSOLE: This is kind of an interim statement. This not the conclusion of the meeting. Let's have 10 minutes.

(Recess.)

MR. MEDFORD: I'm Mark Medford, the licensing manager for Southern California Edison. On my extreme right is Ken Baskin, the executive for licensing; between us is Mr. Rainsberry; and making our presentation today is Bruce Duncil, who works in licensing. I would like to first comment briefly on the agenda. Looking at the second purpose, it says that NRC is to be briefed by the NRC Staff and SCE utility as to the NRC utility actions and recommendations.

Jesse, as you indicated earlier, we are in mid-program. This is by no means the end of our evaluation. We are going to present to you today some of the actions

that we have identified would be appropriate as a result of the event, but don't take this to be the final result of our evaluation of the event.

Having said that, I would like to turn it over briefly to Ken Baskin, who is going to address our attitude in dealing with action statements.

MR. BASKIN: And I will be brief. I think it's important to at least clarify from our perspective this discussion of a few minutes earlier about action statements.

There was no intent, to the best of our ability, to ascertain on the part of the operators or certainly no intent in their training on the part of management to have them resist shutting down the plant. As I think Tim indicated, entering the action statement was really -- would have been relatively insignificant because if you found the problem you would have had to shut down the plant anyway. If you didn't find the problem you could have exited anyway, so it really had no bearing in that context.

In our training of operators, we encourage them not to enter action statements lightly because an action statement at least infers that some portion of plant equipment or systems is not operating properly that would normally be available and therefore could normally be required.

So it's a matter of how one looks at action

statements. We train our people not to enter them lightly and to do whatever else they can before they go into an action statement. The normal situation would be that the things you are doing without entering an action statement would have less impact on potential safety.

It turns out in this case that, had we entered the action statement earlier we might have discovered the situation earlier. But obviously we didn't know that at the time. So, our philosophy is not to look at these lightly and not to enter into them lightly, and that's the reason the operators reacted the way they did.

MR. REED: You would have discovered the electrical situation earlier, not necessarily the check valves.

MR. BASKIN: That's correct. As you indicated, we may or may not have discovered the check valves.

MR. EBERSOLE: Thank you.

(Slide.)

MR. DUNCIL: Our presentation here is geared toward the water hammer event specifically. We'll go briefly over the sequence of events, but concentrating mostly on the feedwater check valves themselves, on the design aspects and to follow up some of the conversation earlier, and then to go into a discussion of some of the corrective actions that we plan to take.

As Mark indicated, our evaluations are still ongoing in many respects and we'll touch on that as we go through.

Relative to the event, we agree that the event is very significant, from the standpoint that we had, essentially, a common mode failure of five safety-related check valves. Additionally, the most significant aspect of the event is the failure of the check valves.

(Slide.)

The root cause of the water hammer event is the failure of those five check valves, and we'll get into the root cause of the failure of those check valves as we get into the presentation.

(Slide.)

Again, briefly, one-line diagram for the feedwater system, the feedwater lines to the generators, the 10-inch valves. I think we pretty well hit the highlights on those. The east evaporator condenser was the one that ruptured when the east feedwater pump was deenergized, and that's what initially started the sequence of events.

MR. MICHELSON: What is the design pressure rating of the piping upstream of the main feedwater pump?

MR. DUNCIL: Basically what you have is a nonsafety-related/safety-related break at the upstream

flange of this valve. Upstream is 360 pound piping; from this point to the generators you have 1350 pound piping. It's all ANSI B131.

MR. MICHELSON: Have you reviewed the heat exchanger designs to see what kind of rating might have been on the tubing? In other words, why did the tubing rupture in the evaporator instead of one of the heat exchangers?

MR. DUNCIL: We have done heat testing and other tests on the feedwater heaters. Obviously the tube here was the weak point in the system.

MR. MICHELSON: Did you look at the wall thickness of the tubing and so forth in relation to the diameters and determine if this is where the rupture should have occurred or have you gotten to that fine structure?

MR. DUNCIL: I can't speak to that. I know this being 360 pound piping, this being essentially over 1000-pound pressure from the west feedwater pump and this pump already failed and this pump secured, this piping saw the full discharge pressure from this feedwater pump.

MR. MICHELSON: Are you also saying the inlet nozzle for the feedwater pump was rated at the same pressure as the exit nozzle?

MR. DUNCIL: Yes. The code break is right here.

MR. MICHELSON: It's not entirely unusual, but

somewhat unusual, isn't it, to rate the suction of the pump at the same pressure as the discharge?

MR. DUNCIL: I'm not an expert in the design, but usually what you do is take a code break at a flange.

MR. MICHELSON: It could be because they use the safety injection pumps that you have to do this?

MR. DUNCIL: That's absolutely right.

MR. EBERSOLE: Let me examine the safety-injection approach to that. Presumably you are in an approach to a hazardous state to a core, you may or may not succeed in injecting, so you are injecting water to the primary loop with potentiality, in this case if something happens -- and I see two check valves in parallel which would permit reverse flow from a primary loop. Am I correct?

MR. DUNCIL: I do know that has been looked at.

MR. EBERSOLE: Is that considered an adequate isolation barrier from the primary loop when that function is in place and you are trying to operate as an injection system? It's the -- the pump casing can't take primary pressure, obviously. That's 2200 pounds.

MR. RAINSBERRY: There's additional pumping, and at least another check valve and a MOV.

MR. EBERSOLE: So there's other ways to intercede.

MR. DUNCIL: The purpose of this slide is to show the major milestones in the sequence of events for the main feedwater hammer event itself.

(Slide.)

We went over that pretty well in the previous presentation. The times are designed to show the time differences between events. There is one typographical error -- I apologize for it -- here. The combined aux feedwater flow was at time 4 instead of time 8. Basically the steam-driven pump completed its 3-1/2 minutes' warm-up cycle at about the same time the electric power was brought on and the electric-driven pump was started, and of course, that led to the water hammer event roughly 16 or so minutes after aux feedwater flow was introduced.

(Slide.)

This slide depicts the -- an isometric of the feed flow lines inside containment. As Mr. Martin pointed out, this B feedwater line is approximately 205 feet in length. It's a horizontal runout to containment penetration. A and C are on the order of 103 and 107 feet respectively. Also horizontal runs.

The water hammer event was caused by slug formation. We'll get into that in the next slide.

We based that on our evaluations that the slug formed in this vicinity here and then traveled down the

length of the pipe toward the feedwater mezzanine area.

MR. MICHELSON: Where is the location of the penetration itself on your isometric?

MR. DUNCIL: Right here.

MR. MICHELSON: Is that an anchor point? Not a bellows, a true anchor; is that correct?

MR. DUNCIL: I believe it is.

MR. MICHELSON: Have you inspected the penetration itself, verified no damage?

MR. DUNCIL: The inspections have been done.

MR. MICHELSON: Can you get through all the piping? Have you actually inspected it?

MR. MEDFORD: I know the penetrations were inspected. There was no damage.

MR. MICHELSON: You are able to do an inspection of that penetration all the way up to the anchor point?

MR. MEDFORD: That's correct.

(Slide.)

MR. DUNCIL: I might preface this slide. I am not a water hammer expert; however, Dr. Chong Chui has been working directly with Dr. Paul Rothe in CREARE -- in fact, CREARE was brought on board about a day after the event to work with us in developing an understanding of the feedwater event.

From that evaluation, the simplified

understanding of it is that as the B feedwater line filled with feedwater, obviously the steam being on top of the feedwater as the pipe fills up, we did have some steam flow that was not only due to condensation but we still have the steam flow due to condensation on top of this, creating turbulence in the water here and generated a slug which developed in the pipe, as I mentioned, up toward the steam generator, traveled down the pipe.

At the time this occurred A and C feedwater lines had already been refilled. You will recall they are approximately half the length of the B feedwater line.

At the time the B feedwater line was filling the auxiliary feedwater flow to this pipe was on the order of about 25 to 40 GPM. So it was filling rather slowly.

The other thing I might point out is, based on our calculations, the actual void fraction in the pipe was between zero and 15 percent at the time that the slug formed. So, as you can see here, we attempt to depict that there was very little area, steam area in the pipe.

MR. MICHELSON: Where are the traps along the pipe? In other words, in what direction is the pipe pitched for drainage?

MR. DUNCIL: There is no real pitch in this pipe.

MR. MICHELSON: There's always a little pitch in a pipe. Do you know it was truly level to begin with?

MR. MEDFORD: The answer is we don't know. Of course, the as-found condition after the event didn't lend itself to that and we don't know from previously existing information.

MR. MICHELSON: There was a possibility that there was a small pitch in this pipe even from growth, expansion, deflection during the life of the plant such that now there was a pool of water that went along the pipe. The pipe might have been completely filled at one point which greatly helps the generation of a water slug.

MR. CATTON: Here is the flow. They talk about water flowing in.

MR. MICHELSON: What bothers me is the water coming in is the warmest water in the pipe. It's cold when it comes in, but it's coming in way back upstream.

MR. CATTON: The steam is being condensed where the water is cold.

MR. MICHELSON: The warmest water, though, is right next to the steam generator and it gets progressively colder way back.

MR. CATTON: And you don't need much cooling to lead to the water hammer.

Is it important that you know that? See, that 15 percent, is it important that you know that? Or is it just important that you know whether or not a water hammer

will occur under those circumstances?

MR. DUNCIL: It was important relative to our understanding how that slug was formed.

MR. EBERSOLE: That slug is flowing toward an open pipe and also into a region where further condensation will take place even if the pipe is closed; right? There are two exit paths for steam, one to condense and one to go out of a hole.

MR. DUNCIL: At this point in time the MOVs and feed control valves were shut so there was no real path for that until the water hammer itself opened up the four-inch bypass check valve. So really, the only flow that was at this point in time when the water slug was formed was due to condensation.

MR. EBERSOLE: Flow into condensation.

MR. DUNCIL: And this, again, I might point out there was only about a four-minute period of time involved -- well, I guess it was more like five minutes involved, so there wasn't a lot of time for this water to heat up, so it was still relatively cold water.

MR. REED: Would you go back to the preceding slide a minute? What I would like to ask is where does the auxiliary feed come in? You may have said. I would like to know how close to the steam generators does it come in?

MR. DUNCIL: The aux feedwater piping is down

near the feedwater mezzanine, which, as you can see, it's upstream of this point. I'm not sure exactly how -- just outside --

MR. REED: One way to prevent water hammer, and of course it was resolved by the NRC before, they talked about J tubes. But there were a couple of plants that decided that wasn't the proper cure. The proper cure was to put check valves right adjacent to the steam generators, quality check valves and that would take care of the water hammer thing.

But you have to get your auxiliary feed on the downstream side of that check valve so you've got your auxiliary feed outside containment rather than bringing it in to right close to the steam generator and then going into the feed path. I'm just looking at your cures. It looks to me like you have to put in a quality check valve right up next to the steam generator but you have to get your auxiliary feed downstream of that.

MR. EBERSOLE: Next to the boiler. Which means long aux feed lines.

MR. DUNCIL: It would in this case.

(Slide.)

As I mentioned earlier, not only did we bring CREARE on line to help us in our evaluation of the feedwater even, we also brought on board Mettek, Incorporated, which

is a company which assisted us in doing metallurgical assessments of the valve damage as they were released from the quarantine list. We also hired Dr. Kalsi to assist in helping us analyze the valve design once that became available to us.

We opened and inspected the feedwater pump check valves and also the 10-inch valves. Basically what we performed was a valve leak checks, blue checks, flapper inspections, and also we took a look at the gaps between the disc and seat.

The blue check is taking a look at the valve, put some bluing compound on it --

MR. EBERSOLE: I know.

MR. DUNCIL: The valve flapper is several pieces. You have the main hinge arm, the disc attached to it with the stud, the nut. There is a locking pin on these nuts, a washer underneath that. And these two lugs here are the anti-rotation devices which essentially prevent the disc from rotating about that hinge arm.

MR. EBERSOLE: When you write the specs for that did you define the potential closing velocity that that valve will see on its seat in a hypothetical case of a pipe stream, upstream of the valve proper and full pressure applied to the seat?

MR. DUNCIL: I can't speak to that.

MR. EBERSOLE: Is there a dynamic specification in procurement that says this valve may face a potential upstream pipe failure, abrupt, in which case it must survive in rapidity of closure the presence of full upstream water and one, thus, must calculate the closing seat velocity and determine that the resilience or inelastic energy absorption process will be sufficient for it to survive? Did you do that?

MR. DUNCIL: I can't speak to that. I don't know.

MR. REED: On the five valves that failed, were these locking pins put in?

MR. MICHELSON: On this slide, am I looking at a 10-inch disc there?

MR. DUNCIL: This is the standard for 10-inch, 4-inch and 12-inch. All are identical, manufactured by Pacific valve.

MR. EBERSOLE: I have to say that these valves are designed against an ancient belief that there will never be any pipes ruptured. The only thing that will happen is you turn the motor off on a pump and it will decelerate, WR squared; it will make a gradual closure and the valve, historically, all it has to see is a nice closing, and never has to see the pipe break. We live in --

MR. KERR: You can tell that by looking at that?

MR. EBERSOLE: Of course. I don't see anything in that that keeps it from being under severe duress if it has to close under those conditions.

MR. DUNCIL: That's a possibility. I know that did not enter into what we found based on our evaluations.

MR. EBERSOLE: Of course that's not what really happened.

MR. DUNCIL: Just to review briefly what our findings were relative to the five valves that had failed, in a number of cases the discs had become loosened. In a couple of cases, the A and B feedwater lines the discs were actually disconnected from the hinge arms. And we did find indications here, like, for example, on the C feedwater line, the disc rotated and cocked such that the valve was opened. Basically the valves are not functioning.

MR. REED: I don't find the locking pins mentioned.

MR. DUNCIL: In most cases, as I recall, those were gone.

MR. REED: Were they ever put in?

MR. DUNCIL: To the best of my knowledge they were.

MR. REED: In other words, you have no evidence that they were?

MR. MEDFORD: We do have evidence. Some records

that they were put in.

MR. REED: You do have evidence, fragments?

MR. MEDFORD: Some records, not all of them.

MR. MICHELSON: You have evidence of corroding or what? As long as I got my question in, talked about the pins, were they corroded or fretted or --

MR. MEDFORD: They showed signs of fretting, but the failures tended to be in the root of the bolt.

MR. REED: You have to worry about chicken or egg here. What came first, chicken or egg? The nut may have failed subsequent to it breaking loose.

I don't like that pin. It looks like a pretty flimsy way to lock a nut on check valve which is flipflopping around. It's a pretty poor device. But if you found evidence that they were put in, that the maintenance gang didn't foul up and leave them out -- and we had another case of a safety valve where some sort of pin or something was not put in, that was clearly established.

MR. MARTIN: Before you go on, some of those did not have pins. In fact, the way the nut was rotated there was no hole through the nut and the staking; the nut was turned over, and so the last time it was put back together it was not put back in the same way it was before and was not restaked.

But the failure of many of these valves -- you see the piece extending down from the bonnet?

(Slide.)

Basically that nut and stud rammed against that, and in some cases it looks like it shattered that attachment.

MR. DUNCIL: I'd also point out on one of the valves, for example, the washer underneath the nut was missing. We did find evidence in a couple of cases where the stud that the nut was on had been badly damaged.

In another case the nut was still attached to the stud; however, it was cold formed on the bottom where the disc had vibrated against it.

So, the level of damage I think -- this kind of addresses that -- will indicate whether that pin was present or not may have not had a significant contribution to the valve failing.

MR. SERKIZ: Mr. Chairman, in the investigative team's report there are photographs. The 12-inch check valves that were used upstream of the pumps, main feedwater pumps, had no hole, no pin, and these are shown as an example of one of them, in figure 6.61 and 6.60.

MR. EBERSOLE: The nut was just torque-turned and that was it. Was it staked?

MR. SERKIZ: I personally inspected this one or

was there --

MR. EBERSOLE: Was there an instructional procedure to reassemble the pump and that was checked out?

MR. SERKIZ: I'm not aware of any. I want to make the clarification, not all had pins or provisions. The 12-inch main ones did not. Your others did have the holes. Those that had failed, the discs were off in the bottom we found -- at least on one aspect, we found neither parts of the nuts or the pin. Maybe the utility can comment whether the other parts were found at some time.

MR. EBERSOLE: Could you comment on that? About the absence of evidence that they were, in fact, secured and staked in place?

MR. DUNCIL: No.

MR. EBERSOLE: Thank you.

MR. DUNCIL: Basically the root cause of the check valve failure was that the valves were oversized. What that means is that when -- at the time that the valves were purchased, check valves were sized by pressure drop, head loss through the valve.

Since 1976 the crane has been revised and one now sizes check valves due to minimum velocity.

These valves were the same size as the pipe, and the minimum velocity required for this check valve to be fully opened is slightly above 100 percent flow velocity on

the line. It's on the order of 19 feet per second. The minimum velocity to keep the valve open is like 18.5 feet a second.

MR. EBERSOLE: When you say there's a resonant cycle, what is the amplitude and does it include physical impacting?

MR. DUNCIL: Let me get to that.

MR. EBERSOLE: Go ahead.

MR. DUNCIL: At 90 percent flow we have the minimum velocity required to keep this valve fully open is less than the flow velocity, so there is approximately a 0.2-inch gap between this nut and the nut stop here, such that the valve disc dangles in the flow stream.

At 90 percent power, 90 percent flow conditions we have about a 12.5 percent fluid velocity reduction and a 24 percent reduction in the force lifting this check valve. So there's about a 2 degree from full open. That's, like I said, about 0.2 of an inch. It resulted in that resonance of 1.3 hertz where that nut was actually impacting the stop inside the valve body.

MR. EBERSOLE: Can't that be heard by some audio detector put on the shell of the valve? Can't you hear this impact?

MR. DUNCIL: I can't speak to that. I don't know how audible that would be. With full flow conditions

and in the location it is, I'm not sure.

MR. EBERSOLE: Maybe too much background noises?

MR. DUNCIL: That's a possibility. Given the location. In addition, when we are talking about 0.2 inch amplitude. However, because of the resonance and frequency, we were getting about 1 million cycles every 12 days. So in six months we are talking about 15 million impacts for this nut on this nut stop.

MR. MARTIN: Very quickly, in June of 1985 it was noted that there was a noise heard downstream of this valve in the feedwater line. As a result they took stethoscopes and tried to localize this noise in the B feedwater line.

It sounded, as it was coming from the valve downstream of this check valve, and the -- their safety analysis determined that certain things -- it could be a loose check valve, could be loose internals in the stop valve, but they made the assessment that even if it did fail there would be no safety consequence because it couldn't get to the steam generator.

All their monitoring at this time, they looked at the other loops and did not detect this anomaly. So my assumption is that if the failure was occurring during that period of time they were not able to hear it. It looks like it was this check valve disc actually laying in the

bottom of the valve because there are indentations, downstream, on the downstream side, that shows where major pieces of metal have been chinked out as a result of this valve hitting there.

MR. EBERSOLE: As a result of this stethoscope -- what you are saying is the valve had already come off.

MR. MARTIN: Probably had already come off.

MR. EBERSOLE: Prior to it coming off there was no incentive to listen to this valve to see whether this function was actually taking place and you were actually beating it to death?

MR. MARTIN: In fact, the detection of this noise in June was subjective. A number of people said they couldn't hear it. Only after certain people said yes, I hear something, they tried the stethoscope technique. They also tried radiographic and couldn't get anything additional.

MR. EBERSOLE: It's a very small movement. But what I'm asking is this, this is a resonance performance that was analytically known prior to this failure; am I correct?

MR. MARTIN: No.

MR. EBERSOLE: It was not. So there was no real incentive to listen, to hear if this impact was taking place on the stop; is that correct?

MR. MARTIN: Although they had had a previous failure of this valve where they also found the disc sitting in the bottom.

MR. EBERSOLE: Okay. Thank you.

MR. MICHELSON: The previous failure of the valve you are talking about, how previous was it?

MR. SERKIZ: It's detailed in the team's report. There's a section in there starting on page 6.13, it talks about that, valve failure-related findings.

Prior to the upgrade to the seismic requirements, there was a period of time that the utility did open up these valves and actually inspect them during the fueling outages. Early on, in the first several of them they found there was wear and tear and replaced the pins and the discs and so on. And that, again, as I say, without going into this, is summarized in here.

I can't give you a reason on why, after a period of time we shifted into another mode and relied totally on IST. But we found in the maintenance history that they had inspected them, they had replaced the innards. And for a while at least -- two refueling outages -- became a way of life and then it sort of slipped into the background.

MR. MICHELSON: I guess it's correct to assume that the normal flow velocity at least used to be on the order of 20 feet per second; is that right?

MR. DUNCIL: On that order. 18 to 20.

MR. MICHELSON: What is it now with the reduced power requirements?

MR. DUNCIL: 12-1/2 percent reduction.

MR. MICHELSON: Still approaches 20 feet per second?

MR. DUNCIL: It was 18 to 20. It's still 17 to 18 feet per second.

MR. MICHELSON: The vendor, I gather, told you about the criticality of flow?

MR. DUNCIL: As I pointed out, these valves were oversized.

MR. MICHELSON: But how did you know you had a problem with your critical lower velocity?

MR. DUNCIL: We found it out in our subsequent lower evaluations.

MR. MICHELSON: Did you do a test at which you saw the valve fluttering and determined at what point it ceased to flutter?

MR. DUNCIL: We took a look at the valve design. Essentially what -- how they sized these valves are with minimum velocity. There are equations with coefficients to determine what the minimum velocity is --

MR. MICHELSON: You can calculate this but you can't easily calculate the effects of downstream

fluctuations. The contribution of downstream turbulence could far outweigh other contributions from normal turbulent flow.

MR. CATTON: That depends on what the number is.

MR. MICHELSON: It was running 20 feet per second. I suspect it's quite high.

MR. CATTON: He'd have to have the throttling valve pretty damn close to the check valve.

MR. MICHELSON: It is pretty damn close.

MR. CATTON: How close?

MR. MICHELSON: Three to four feet. That's close. That's a couple of pipe diameters -- well, three pipe diameters away. And generally the rule of thumb is it's got to go out at least five or six before you can start to get rid of the turbulent flow. He can't calculate this. I think he has to test it, and that's why I wondered if he was actually watching it or just calculating it. I don't think you can calculate it.

MR. CATTON: I don't think they know what the lift coefficient is, either.

Does that nut bang up against the stop all the time?

MR. DUNCIL: At 100 percent flow, this valve -- this nut should be -- should impact -- should be resting on that stop since the minimum velocity required to keep the

disc full open is lower than the stream velocity. At 90 percent power that's not the case. At 90 percent power, it's going to be rapidly vibrating against that.

MR. CATTON: Doesn't that bang up the threads on the nut? That seems to be poor design.

MR. EBERSOLE: What's the technique that tells you that you are against the stop and steady on course? There's no way to tell that external to the valve, is there? Not by listening? Not by anything?

MR. DUNCIL: I can't speak to that. I'd say probably not.

MR. MICHELSON: Every time you start up you are going go through a period of time where you have lower velocities and you are going to be going through this mode.

MR. CATTON: It's just a flaky design.

MR. EBERSOLE: Some do a better anvil.

MR. CATTON: Those things get washed out because they don't work.

MR. DUNCIL: As you do startup and shutdown there will be some impact, but, again, we are talking about very limited periods of time compared to normal full power operation for 180 days or so.

I might point out, based on this evaluation, we have concluded that the valve design needs to be replaced.

The next slide will depict what design we are

going to. As you recall, the primary failure mechanism, the root cause of the failure was that the valves were over sized.

The Atwood-Morrill design that we are looking at here is a one-piece disc assembly so there is not a hinge pin or any kind of assembly that would come apart that would cause the disc to separate from the hinge. In addition to that, the valves are going to be sized such that they will be full open at down to 70 percent flow.

MR. EBERSOLE: Before you leave that, are you going to have that little lip at the bottom? Are you going to validate that these can intercept a full reverse flow from a hypothetical reverse flow upstream or would it just peel that lip off?

MR. DUNCIL: I can't speak to that.

MR. EBERSOLE: Somebody has to write the specs.

MR. MEDFORD: Jesse, we don't know what the spec says on this valve, but one of the things we want to take away from this meeting is to check and see what the dynamic requirement is.

MR. EBERSOLE: That's all.

MR. REED: I don't think that drawing is very representative of the way the disc --

MR. EBERSOLE: I'm looking at it in profile. I understand.

(Slide.)

MR. DUNCIL: As a result of our evaluations, the following modifications are intended. We want to replace the eight Pacific check valves with Atwood-Morrill designs, the two 12-inches, the three 10-inch check valves and the four-inch check valves.

We are going to provide in-service test capability for the replacement valves.

We are going to slope the B feedwater pipe inside containment. Basically what this will do is make the B feedwater line improve its -- should I say decrease its susceptibility to water hammer event to the level that ANC are susceptible.

MR. MICHELSON: Which level are you sloping it?

MR. DUNCIL: I believe the direction is toward the generator.

MR. MEDFORD: Away from the steam generator.

MR. DUNCIL: We have the valves with IST provision in each feedwater line inside containment.

MR. EBERSOLE: Are these the ones close to the steam generators?

MR. DUNCIL: Yes.

MR. EBERSOLE: Does that mean you are obligated now to take long aux feed lines and go upstream of those?

MR. BASKIN: That's something we have to look at

further.

MR. REED: In making that statement, in saying you probably should put the aux feed lines downstream of the closeup -- on the main steam line -- that's the way I have seen it done quite successfully. You'll have to look at whether you can leave them outside containment and injecting into the common line, whether or not that gives you the same protection against water hammers.

MR. DUNCIL: We were going to provide for automatic closure of the main feedwater following unit trip and loss of NFW pumps. That would not have precluded water hammer but it would have allowed the lines to fill more quickly.

We are going to evaluate the addition of void-sensing device with a control room alarm. What that's going to do basically is give us an early indication of void formation in the line.

MR. MICHELSON: What kind of device are you going to use for that?

MR. DUNCIL: Probably RTD.

MR. MICHELSON: For void formation in the pipe? Is that what it is?

MR. DUNCIL: Steam.

MR. CATTON: Actually not an RTD.

MR. MICHELSON: What are you going to do with

temperature --

MR. CATTON: It measures heat transfer between heat and water.

MR. MICHELSON: Okay, he's going to use a heated therm -- he's going to use a thermocouple and can tell whether the top part of the pipe is voided? That could be potentially helpful. I'm not sure. He's also pitching his pipe away from the steam generator now --

MR. CATTON: Do the pipes come in horizontal right to the steam generator?

MR. MICHELSON: No. They come up.

MR. CATTON: So if they put the sensor in that line --

MR. MICHELSON: Near the steam generator. That will be helpful.

MR. CATTON: Where are you going to locate these sensors?

MR. DUNCIL: That's still under evaluation. Both the type and location are under evaluation.

MR. RAINSBERRY: It's fair to say we don't have a design in place so we can say something is going to be done now.

MR. REED: I'd be more interested in putting my money in prevention rather than monitoring in this case. Because water hammer is a very sudden thing and fleeting

thing and transient thing and I don't know that you could get anything -- if you got anything that could reliably tell you it happened you could do anything about it.

MR. CATTON: You monitor whether or not to see if you have voids.

MR. REED: You can have voids like that -- (snapping fingers) -- on a feed line break?

MR. CATTON: Oh, feed line break, that's a different story. But here they are concerned about a draindown through the lines that will take place slowly. And then just want to know not to refill them.

MR. REED: How many sensors are you going to put on and where?

MR. CATTON: I don't know, but I suspect it wouldn't be too difficult to figure out. I'd put one right up near the steam generator, and if it shows vapor in that vertical run, I would assume I would have a water hammer unless I did something to prevent it.

MR. REED: I'd put my money in good design.

MR. CATTON: I would not refill that tube other than very, very carefully.

MR. EBERSOLE: Go ahead.

(Slide.)

MR. DUNCIL: The next slide depicts the general modifications that we are in the process of pursuing; we

are going to install control room indication of blowdown status. I might also point out -- the asterisk and double asterisk are on the next page, but basically the double asterisks are things we are doing during the current outage; double asterisks are things that don't have a schedule associated with them yet.

We are going to provide all the blowdown isolation on AFW actuation.

We are evaluating the possibility of providing for automatic loading of the diesel generators on loss of power. Again, a schedule hasn't been identified for that proposed modification. We are going to evaluate alternatives for providing an immediately available backup source of off-site power.

We are going to install additional protection for the auxiliary transformer feeder cabling. Again, that goes back to the prevention of water damage and mechanical damage to the cabling that could lead to grounds.

Modifications to preclude spurious actuation of safety injection will be implemented.

We are going to modify the tech support computer for automatic restart following restoration.

MR. EBERSOLE: Let me ask you about that. Are you going to augment and improve power supply to the computers so you don't experience an outage?

MR. DUNCIL: That's where this is; it's for both the title tech support computer as well as vital bus 4.

MR. EBERSOLE: That's right. Otherwise you shouldn't call it a vital bus.

(Slide.)

MR. DUNCIL: We are going to determine and correct the cause of the spurious red-phone ringing; going to install a control room clock not dependent on AC power; and we are going to review the control room indication of vital bus status as part of our design review process.

We are going to modify the current limiting bypass reactor breaker design such that the diesel generator breakers can be closed. This was something that was identified during the event. It wasn't involved directly with the event, but it was something we identified in the course of our evaluations.

MR. EBERSOLE: What about the matter of having to manually close main-stream isolation valves? Are you going to look into the advantage or need for having that remote manual?

MR. DUNCIL: I know it has been looked at.

MR. EBERSOLE: I recall the fellow that had to run when he was down there, facing the closure of it.

Right now it's driven by an air wrench, isn't it?

MR. BASKIN: It's, in effect, a manual valve.

MR. EBERSOLE: He has a socket wrench of some sort driven by air and he has to go up and hold it against it and it doesn't sound like a monumental X-million-dollar expenditure to that wrench from someplace besides right there.

MR. BASKIN: What it amounts to as soon as we -- we put some sort of motor operator on the valve.

MR. EBERSOLE: Right. Analogous to the one he holds in his hand.

MR. BASKIN: Probably a little more expensive than the one he holds in his hand. We have not discussed that. It's on our list and there's lots of things we are considering. We haven't discussed it, but it's certainly not in the area of something we decided not to do, either.

MR. EBERSOLE: This is one of the very few plants that has no ability to isolate steam flow from a common agent path and thus faces, well, the loss of steam supply. One of the only two aux feed pumps you have.

MR. BASKIN: That's correct. That's correct.

MR. EBERSOLE: That can occur very quickly and that leaves you on one pump, doesn't it?

MR. BASKIN: After this outage we will have another pump, so in effect we have two --

MR. REED: In your review of that I asked the question: Did you follow the power boiler code. You said

yes, in California they have it. I have to think that maybe California was different from Massachusetts at the time. Because at the minimum you would have to have a stop check there in the steam line because you have multiple steam lines, and therefore, for industrial safety and maintenance and operations, you have to have a stop check, a nonreturn.

I think you should look closely at whether or not you, perhaps, shouldn't go a little further in your thinking and having nonreturn valves at each of those individual steam generator lines as well as a stop valve. The trend, of course, has gotten even further than that. Now they have a quick-closing outgoing valve and a nonreturn in each line. You better look a little more closely.

MR. EBERSOLE: How does this plant stand it when it experiences -- I forget which one -- the massive steam tube generators, where it's very nice to be able to isolate the bad steam generators and operate on the others. When you have multiple steam tube generator failures on one, evidently they feed to the secondaries on all sides; there's no way to isolate them; right?

MR. MEDFORD: That's correct.

MR. EBERSOLE: How do you get out of that? The other plants have a neat way to do that, they shut off that

steam generator.

I presume this has been analyzed for the worst case of steam generator tube failure and the result to the public?

MR. RAINSBERRY: It has been, yes.

MR. EBERSOLE: That was done in the presence of no isolation on the secondary? And it came out all right? Well, it must have.

MR. RAINSBERRY: That was reanalyzed as part of SAT, wasn't it? It was reanalyzed since the 1980s time frame.

MR. EBERSOLE: Was it reanalyzed for the presence of AC power where you don't have the condenser into which to feed the primary loop?

MR. RAINSBERRY: Yes. All our accidents have to consider loss of off-site power.

MR. EBERSOLE: So you dump the primary loop into outer space through the dump valves?

MR. RAINSBERRY: That particular procedure has the cooldown trying the get the pressure equalized on the two sides as fast as you can.

MR. EBERSOLE: Has to be on all steam generators?

MR. RAINSBERRY: They are all connected together.

MR. EBERSOLE: All right. Go ahead.

MR. MICHELSON: Do you use a feed and bleed

system to replenish primary-side water?

MR. RAINSBERRY: Safety-injection system and then charging is used. The secondary side is used to -- in the early stages.

MR. MICHELSON: But in the steam tube rupture cases you eventually have to cease putting primary side water in?

MR. RAINSBERRY: Correct.

MR. MICHELSON: Hopefully you'd isolate the ruptured generato. but in this case, you may not be able to isolate the ruptured generator.

MR. RAINSBERRY: You have the capability, with the safety-injection system, in combination with charging, to make up however long you need to based on the fact that you can isolate that generator. And then you cool down using the secondary side.

MR. EBERSOLE: Just discharging into atmosphere?

MR. RAINSBERRY: Right. And then the doses have been evaluated.

MR. EBERSOLE: Okay. Go ahead.

(Slide.)

MR. DUNCIL: The conclusion is the most significant aspect of this event is the failure of five feedwater check valves. The check valve failure was a result of inadequate design and that is the root cause of

the valve failure.

Implementing the modifications we outlined --

MR. REED: I like to have operating companies blame designers for inadequate design. They haven't done it enough and the NRC hasn't done it enough, either. But in what I've heard here I think, sure, it was inadequate and lousy design. But I think that the maintenance folks here could have been a little bit more alert to the fact that they had lousy design, based on what I hear about the maintenance history and these pins and the way these things work.

The way you find most of the time inadequate design is for the maintenance folks and the operating folks to see that it's no damn good and do something about it.

MR. EBERSOLE: That's a common problem. Operating people tend to operate in their own sphere of activity and just fight the plant and be proud of the fact that they can run a booby trap, if they can do it.

Do you have some sort of backflow from operating and maintenance people into the design defect or shortfall area so you really get, you know, a documented, stated requirement that they examine each failure in the context of whether they got a good design or not? It's not a common thing to have that.

MR. BASKIN: We don't have a routine backflow of

information. We do have systems through our nuclear safety group, and our so-called ISAG get into some of these things. And it's, you know, by definition the more important things are where somebody has to define what's important and what isn't. In this case, it wasn't -- back in the '70s and early '80s, we didn't have that when we had the first check valve failure.

But I think it's important to recognize here that what Bruce said was correct. The root cause of the water hammer was the failure of the check valves. The check valves were poorly designed, and I agree wholeheartedly with what Glen said, that we had numerous opportunities to pick it up and didn't.

That's different than us describing the root cause of the event, and I want to make that distinction because I don't think we were at that point yet.

MR. EBERSOLE: At some point in the maintenance process you think the check valve design should have been challenged and it was not?

MR. BASKIN: I'm sorry?

MR. EBERSOLE: At some point in the maintenance and operation of the plant the check valve design should have been challenged and it was not?

MR. BASKIN: Sitting here today it's easy to agree to that statement. The question is why wasn't it?

And prevent such things in the future.

MR. EBERSOLE: Isn't this part of the mindset on the part of operations people, and maintenance people, that "we are going to run this booby trap until hell freezes over and that's the pride of our occupation."

MR. KERR: There's also the maxim that says hindsight is a lot better than foresight.

MR. EBERSOLE: Sure. You have to wait until it really happens.

MR. REED: I have always found a healthy attitude that the operators and maintenance people always want to find the design wrong, absolutely no good and that's why they have to do some work here today. And, on the other hand, the designer wants to say that he is sacred and never did anything wrong. There's a healthy competition but there isn't any referee yet with a big club.

MR. MICHELSON: Could you clarify for me what check valve failures were found by inspection or other reasonable means prior to this event, other than the one back in '74 or '76 or whenever? Were there other cases where you had taken check valves apart or other similar manufacture and found the damage and just fixed it and put it back in?

MR. DUNCIL: I think based on what Mr. Martin had discussed earlier, one of the early maintenance records

in '75 indicated that the valve was opened and the entry was basically just repaired.

MR. MICHELSON: That one we've heard about. Are there any others? Or is that the only time you ever saw damage to these check valves until this event?

MR. MEDFORD: That's the most significant, but there are --

MR. MICHELSON: Wait a minute. Don't tell me most significant. Were there --

MR. KERR: Let him finish.

MR. MEDFORD: There were others.

MR. MICHELSON: Now that the event has occurred you must have gone back and checked all your records to see what has happened. How many lesser significant observations were there?

MR. MEDFORD: I haven't seen that quantified.

MR. MARTIN: I might respond. There was a period there where almost every refueling outage they went in and refurbished the valves and in many cases replaced the disc. You wouldn't go through the process of replacing the disc unless you found some major damage that simple grinding would have fixed.

Our licensee is faced with the same problem. The records don't tell you much more than "replaced the disc." Doesn't tell you why or what the problem is, and

there's nobody around that seems to remember those details.

MR. MICHELSON: But there must have been a problem or they wouldn't have replaced the disc?

MR. MARTIN: Every review and outage.

MR. MICHELSON: This is not an isolated occurrence in '76, but rather there was a lesser degree of problem. That's what I was trying to get a feel for. Every outage?

MR. MARTIN: There was a period there, from the information we had, from about '76 to '81, I guess it is, every refueling outage we found some information that said discs were replaced or nuts were replaced. Things like that.

MR. MICHELSON: Once a year then?

MR. RAINSBERRY: 15-month cycles.

MR. BASKIN: Two, possibly three refuelings.

MR. MICHELSON: So it would not have been a total surprise to have found this happen. At least it was happening to a lesser extent in the past?

MR. BASKIN: Yes. I think in hindsight I don't know that replacing the disc indicates necessarily severe distress to the valve. You know?

MR. MICHELSON: It indicates enough that you went to the expense of replacing it.

MR. BASKIN: And it certainly indicates it

doesn't seat tight enough to pass the tests.

MR. EBERSOLE: Ever if you found they were working fine that by no means says in the aspect of an upstream pipe break that they would have intercepted flow. They might have crashed right through even though they had been operating up to that time with no problem at all.

I'm saying long-time experience with valves is no proof that when called upon in duress to do what they have to do they will do it at all; do you follow me?

MR. BASKIN: Yes.

MR. EBERSOLE: There has to be in the specs or analysis or unique one-time test or something, and it's not something you develop over X years, 20 years, whatever -- it stands in the background and waits for it to happen.

MR. MICHELSON: Well, there was at least a one-time test of a severe water hammer against the disc and it didn't integrate, but that's about the worst case I guess they've ever ever seen. A pretty good case.

MR. DUNCIL: Relative to that conclusion, I would like to point out in the past years we have operated at 90 percent power. The valves have seen more damage than would normally be seen through several cycles. There really isn't any criteria that I am aware of as to what the requirements are replacing the disc. What we said earlier, following on what Tim was saying, the maintenance records

were in existence, 10 or 15 years ago, nowhere near come to the capability of being able to predict detailed failure mechanisms in retrospect.

MR. EBERSOLE: This wear you are talking about, I can only see two wear patterns. It would be on the pivot shaft where it works or impacting on the nut and its bolt. That's the only wear there is, isn't it?

MR. DUNCIL: As far as I'm concerned.

MR. EBERSOLE: Of those you don't mention any wear on the pivot pin at all.

MR. DUNCIL: As I recall, there was very little wear on the pin.

MR. EBERSOLE: So it focuses on the impact on the stop. That's the only wear there is.

MR. DUNCIL: Essentially.

MR. MICHELSON: On your check control valves, since you indicated it was oversized for various reasons, was the flow control valve also oversized so they had to do a considerable amount of throttling with it even at 100 percent power? The only 100 percent power?

MR. DUNCIL: I can't speak to that.

MR. MICHELSON: In other words, unfortunately you never supplied us a drawing of the trim internals of that flow control valve, which I think would be quite important to have.

MR. CATTON: That would tell you about the downstream turbulence --

MR. MICHELSON: How it might have compared if they reduced it another 10 percent full. How much they were throttling. I don't even know what kind of a valve it is in terms of the trim.

You don't really know the kind of trim in that flow control valve, do you?

MR. MEDFORD: No.

MR. MICHELSON: Do you have an outline drawing of the internals?

MR. MEDFORD: No, we don't.

MR. MICHELSON: Could you arrange to send one to our federal representative, an outline of just that flow control valve?

MR. MEDFORD: Certainly.

MR. EBERSOLE: In inspecting the valve do you usually find any degree of turbulence upstream of the valve in addition to the mass flow rate?

MR. MEDFORD: No.

MR. EBERSOLE: Just a statement about so many feet of pipe and that doesn't say what you are doing upstream of that point?

MR. MEDFORD: That's correct.

MR. EBERSOLE: So the specs tend to be a little

on the loose side in this context. Well, they always have been.

MR. MICHELSON: There are certain rules of thumb you use in designing to keep your flow control valve far enough removed from the check valve. Those rules of thumb are well known by designers but not always abided by.

MR. CATTON: You have to worry about how far it is from a bend, too. Because a bend creates a secondary flow that will cause an oscillation.

MR. EBERSOLE: Let's go. Carry on.

(Slide.)

MR. DUNCIL: Our last conclusion: implementing the modifications outlined above will eliminate the identified check valve failure mechanism and in general improve plant performance.

That concludes my presentation.

MR. MICHELSON: The only comment on your last item I would have is that I think you really haven't yet addressed the reason why the valve, the previous valve was failing. And it may be that that reason still exists and that your new valve will not necessarily fare much better, although it might be designed to take the beating a little better.

MR. DUNCIL: Again, we believe that the failure mechanism was based on, first of all, the valve being

oversized such that it was not open in the flow steam fully. The new valve design will allow the disc to be fully opened down to at least 70 percent flow.

In addition to that, we believe the failure mechanism of the valve, because of the impacts, was due to the multi-piece construction of the hinge and disc assembly. With the new valve design we have a one-piece assembly and it will not be subject to the same mechanism.

MR. MICHELSON: My comment relative to your 70 percent flow is that depends upon whether you have well established flow or whether you have a highly turbulent condition out of your flow control valve. If you have a highly turbulent condition it may still not be stable and you may find a surprise.

MR. MEDFORD: We share your concern about the flow regime in that area. That's one of the reasons why we are adding the check valves.

MR. MICHELSON: I don't know how that helps you much, though. How do you figure that helps you? It's a little more impedence in the system, but --

MR. DUNCIL: The check valves inside containment would preclude, should those valves ever fail again, it would be a backup. It doesn't reduce the turbulence in the line.

MR. CATTON: It's quite some distance, though --

MR. MICHELSON: It's about three, four feet. He's going to have the same check valve right next to it.

MR. CATTON: He's going to move the set inside?

MR. MICHELSON: He's going to put an additional one inside was my understanding.

MR. RAINSBERRY: Yes.

MR. MICHELSON: And replace the one right next to the flow control valve, and I just wondered why the world changed already?

MR. RAINSBERRY: We are also adding a provision for another flow control valve.

MR. EBERSOLE: That it? Thank you.

The remainder of today, we are of course out of time already, just a general discussion and summary conclusions and future ACRS actions, and I have discussion here between what was thought to be said tomorrow -- it's an hour and a half -- at the end of which where we have a summary of the review, NRC utility reaction and recommendation for specific plans, specific and generic actions, summary conclusions -- I think this is premature at this time to say this.

What we need to identify now is to what degree we can get simply support for informational discussion tomorrow, late in the afternoon to the full committee? Just to tell us where we are in this investigative effort

and what we can say at this time with no inference that we are by any means done.

MR. KERR: Do we need an informational meeting?

MR. EBERSOLE: I think the committee members are much interested in what's going on. I wouldn't spend an hour and a half on it Bill, but I would like to spend some time. To what extent can we get some support for an abbreviated statement of where we stand in this investigation?

MR. MEDFORD: A problem is we just learned of the meeting this week.

MR. KERR: They say we don't know quite why this happened and what we are doing about it --

MR. EBERSOLE: It's premature? That's one conclusion we could draw. I have no way of feeling -- gee, let's have a discussion.

MR. MICHELSON: The committee may want to hear about the event in general, but the Staff could make such a presentation. Nothing controversial, I don't believe, about what happened. But rather some of these other requirements.

MR. EBERSOLE: That's all I'm after, a news report of where we are and what went on.

MR. MICHELSON: But no conclusion.

MR. EBERSOLE: No conclusion reaching whatever.

We are still in the middle of this and maybe a projection of where we will be when. That's about all I can say.

They have had the report already and they are certainly interested in it.

MR. REED: I think if the Staff is going to make a less than one-hour presentation to the full committee, they should try to get away from all these extraneous things, 18 or 20 issues.

I sort of boiled it down real quickly to only about three or four significant aspects with respect to this event. One is the design thing. I see another that there wasn't enough alertness on the part of the maintenance people, the operators -- get it down to that. I think a lot of this other electrical stuff doesn't go along the major path.

MR. EBERSOLE: It doesn't get to the core by any means. We could intercept the preliminary.

MR. HERNAN: Jesse, Ron Hernan with the Staff.

We have been discussing with the ACRS Staff for at least 10-days to two weeks, full committee. And we, because of scheduling conflicts and so forth, are not in a position to support a presentation at the full committee meeting. It's my understanding that you were going to summarize.

MR. EBERSOLE: Certainly we could summarize

ourselves.

MR. HERNAN: We also had not invited the Licensee to attend the full committee meeting.

MR. MICHELSON: Had not?

MR. HELTMAS: Had not. I guess our feeling, if the team was unable to be there to make a presentation it would not be appropriate to have the Licensee.

MR. SAVIO: You would have some scheduling information?

MR. HELTMAS: Yes. We can discuss the overall schedule.

I did want to mention, because I don't think I heard it mentioned this morning, Mr. Stello has issued a letter as of February 4th, which I believe you have copies of, to Mr. Dent, Mr. Taylor and Mr. Martin, which lays out fairly specifically what the issues are the Staff is going to work on and to some extent, a schedule, although he's asked these people to respond with their detailed schedule of the action items scheduled. Also with the idea that the actions -- that they would report back in three to six months.

But I can discuss with the full committee where we are going from here.

MR. EBERSOLE: The general aspects of where we are.

MR. HELTMAS: And what we conclude, what the team concluded were the main issues.

MR. EBERSOLE: We can reduce this down to a nalf hour or something and go that wav with just you and ourselves to comment on what we heard. And it certainly focuses down to the check valves in the final analysis.

MR. MICHELSON: To be sure I understood what you said, Ron, are you saying it will be three to six months before the plant starts up again?

MR. HELTMAS: No. No. Absolutely not.

MR. MICHELSON: Are they on any kind of hold presently? What does the Licensee have to do before they are allowed to start up again?

MR. HELTMAS: I think I'd rather have Mr. Dudley address that.

MR. DUDLEY: I have one additional slide.

MR. MICHELSON: Okay. I thought that we were going to hear all of that in the full committee and therefore I didn't raise the question.

MR. DUDLEY: This slide is just an elaboration of the actions in particular the Staff is performing in order to respond to the memo giving us direction.

(Slide.)

Region 5 has been given the lead for facility restart for San Onofre. NRR the be providing information

to Region 5 and NRR will be providing the review of the technical design questions that are mentioned and come up in the EDO memo and the IIT report.

INE was given the generic lead regarding the possibility or probability of generic problems with check valves, and INE is also going to look at the generic adequacy of the in-service testing program and our requirements related to check valve problems.

NRR to also assess the need of whether it is required to reevaluate the water hammer USI, to specifically look at the time of condensation-induced water hammers, this type of water hammer that occurred at San Onofre.

MR. EBERSOLE: Is there an act program of some sort looking at other plants that might be on the borderline of this same condition? Old plants?

MR. DUDLEY: Well, INE -- well, let's see. On the water hammer portion or the check valve?

MR. EBERSOLE: With relation to check valves which invites water hammer.

MR. DUDLEY: Al, can you speak to that?

MR. SERKIZ: To pick up the point that was just made, I think the check valves are the key generic question. This is the first time that I am aware of in this country, or anywhere, had such a gross failure of check valves. One

of the points made by the IIT I think is correctly made, resolution of water hammer USI A-1 was based fundamentally on looking at where water hammers had occurred. If we have a situation that is as bad as this check valve failure with 10, then I think that is the issue to be looked at and cured. We will -- and I don't have the exact plans right now because one of the items that came back in a Stello memorandum was to look and see if we want to reopen the safety issue.

MR. EBERSOLE: You mean the water hammer?

MR. SERKIZ: Water hammer as a safety issue. We did look at condensation-induced water hammer. We do know -- this is well known -- this type of water hammer will give you the largest structural loadings. To reopen the issue on the basis of steam condensation water hammer, I'm giving you my personal view, I don't think this is the way to go. I think we want to work in concert with the people that are looking at the check valve failure and see if that, in conjunction with the fact in a check valve failure or leakage would lead to this situation, that would be a better way of looking at whether we want to reopen the water hammer issue.

MR. EBERSOLE: Is there contemplated some sort of issuance to other owner/operators about this matter here and a requirement that they review their own check valve

operational practice?

MR. SERKIZ: I believe INE has already sent out an information notice.

MR. DUDLEY: Right. Early January.

MR. EBERSOLE: No requirements specific action be taken or any backflow?

MR. DUDLEY: Information notice.

MR. EBERSOLE: When did that go out?

MR. DUDLEY: January 6, something like that.

MR. MARTIN: That's correct.

MR. EBERSOLE: Ron, we can report that to the committee, the essence of this slide here.

MR. MICHELSON: You might want to add that there have been several water hammers in the HPSI return line feedwater on boiling water reactors in the last two years, some of which have been dislocated pipes and so forth, and they are caused by partial voiding of the feedwater line and then subsequent injection of feedwater and then water hammer and that has led to damage of pipe but not check valve, as far as I know. But it was caused by leaky check valves, so you might want to look at HPSI feedwater return.

MR. SERKIZ: Just to answer that very directly, I think we are going to raise the question again on reopening. We'd want to look at the occurrences, water hammer occurrences that have been reported over the last

three years and derive on that an insight on whether we should reopen the issue.

All I was trying to say was in this case where you had such massive voiding of feedwater lines, it was a very gross type of check valve failure, first time, first experience.

MR. EBERSOLE: Go to the front end -- okay. Thank you.

MR. DUDLEY: I know you probably want to finish. The NRC will meet with the utility on February 19 at the Region 5 office to discuss items required for restart. The utility will meet with the Commission sometime in March 1986.

The originally scheduled restart date prior to the water hammer was May 20. Due to the extensive modification I don't know what the current restart date is or if that is not the current restart date.

MR. MICHELSON: One observation, your INE is going to look at the check valve problem. Traditionally the valve investigative expertise hasn't been in INE, but rather in NRR or research, where the work was being done. Is there some rationale for why INE is looking at this problem instead of NRR?

MR. DUDLEY: I can't say why EDO made that assignment but I know they are aware that EDO has had

experience.

MR. MICHELSON: If you want to go back and look at past operating experience and so forth, generally AEOB has been doing that and not INE. They only looked at the short-term, next-30-day kind of things. Is there some rationale again for the selection of INE to do this job?

MR. DUDLEY: I can't speak for Mr. Stello.

MR. MICHELSON: I wouldn't think you'd want to.

MR. BASKIN: If I could add two quick points. Number one, recognizing it's premature and things may change, but as of this moment in time we hope and expect to maintain in a May 20 restart date. Again, that may change based on other things.

MR. MICHELSON: Is there an actual holding order right now?

MR. BASKIN: Yes.

MR. MICHELSON: You have a 50.54?

MR. BASKIN: We have a confirmatory action letter from the Region.

MR. MICHELSON: That says until such time as the Region says "go" you have to hold fast? Thank you.

MR. EBERSOLE: I'll be depending to some degree on the subcommittee here to make comments when we get into this 30-minute session.

MR. BASKIN: Jesse, I said I had two quick

comments. I have one other. The other -- and I think it's important for the subcommittee's understanding, but not shown on any of the slides -- but one of the th'ngs we are doing as a result of this effort -- it was started earlier but we ' /e expanded it -- is to do what we call a complete review of the material condition of the plant. Recognizing it's an older facility, this event started as a result of failure of a cable, there will be a complete review of the overall conditions to make sure the plant is up to the standards, as far as material conditions, that we believe it is. But we're going to make sure.

MR. EBERSOLE: You mean in the context of aging?

MR. BASKIN: Aging and wear and all that sort of stuff.

MR. EBERSOLE: Any further comments? We have another meeting at 1:30 here, so we will conclude this meeting.

(Whereupon, at 12:30 p.m., the meeting was adjourned.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceedings before the UNITED STATES NUCLEAR REGULATORY COMMISSION in the matter of:

NAME OF PROCEEDING: ADVISORY COMMITTEE ON REACTOR SAFEGUARDS SUBCOMMITTEE ON THE WESTINGHOUSE WATER REACTORS

DOCKET NO.:

PLACE: WASHINGTON, D. C.

DATE: WEDNESDAY, FEBRUARY 12, 1986

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission.

(sigt) Joel Breitner

(TYPED)

JOEL BREITNER

Official Reporter

ACE-FEDERAL REPORTERS, INC.

Reporter's Affiliation

NRR STAFF PRESENTATION TO THE
ACRS

SUBJECT: RECENT SAN ONOFRE 1 LICENSING ACTIVITIES

DATE: FEBRUARY 12, 1986

PRESENTER: RICHARD DUDLEY

PRESENTER'S TITLE/BRANCH/DIV: SAN ONOFRE 1 PROJECT MANAGER
PAD#1:PWR-A

PRESENTER'S NRC TEL. NO.: 49-27218

SUBCOMMITTEE: WESTINGHOUSE WATER REACTORS

RECENT LICENSING ACTIVITIES
SAN ONOFRE, UNIT 1

- SHUT DOWN FEBRUARY 27, 1982 FOR REFUELING
- SEP REVIEW RAISED CONCERNS RE: ABILITY OF PLANT TO MEET ORIGINAL SEISMIC DESIGN OF 0.50G
- SCE COMMITTED TO UPGRADE TO 0.67G
- NRC AUGUST 11, 1982 ORDER PRECLUDED RESTART UNTIL SEISMIC CONCERNS RESOLVED
- PLANT RESTART WAS UNCERTAIN
- SCE DEFERRED UNIT 1 LICENSING WORK, EXCEPT FOR SEP ACTIVITIES
- LICENSING ACTION BACKLOG ACCUMULATED
- SCE SUBMITTED RETURN-TO-SERVICE PLAN ON DECEMBER 12, 1983
- SEISMIC UPGRADE OF STRUCTURES, ELECTRICAL SYSTEMS AND PLANT EQUIPMENT NEEDED TO ACHIEVE HOT SHUTDOWN
- PROPOSED INTEGRATED LIVING SCHEDULE METHODOLOGY
- NRC ALLOWED RESTART IN NOVEMBER 1984 AFTER SEISMIC UPGRADE

PAD#1:PWR-A:NRR
RICHARD DUDLEY
2/12/86

- o ONGOING SEP PROGRAM ISSUED DRAFT IPSAR (NUREG-0829) IN APRIL 1985
- o STAFF BRIEFINGS TO ACRS
  - SUBCOMMITTEE - JUNE 19, 1985
  - FULL COMMITTEE - AUGUST 9, 1985
- o ACRS LETTER ISSUED AUGUST 13, 1985 SUPPORTING STAFF'S CONCLUSIONS
- o SCE PLANNED TO OPERATE SONGS 1 UNTIL NOVEMBER 30, 1985 AND SHUTDOWN FOR UPGRADES IN ACCORDANCE WITH ILS
  - COMPLETE SEISMIC MODIFICATIONS
  - COMPLETE EQUIPMENT QUALIFICATION
  - COMPLETE FIRE PROTECTION MODS
  - INSTALL DEDICATED SHUTDOWN SYSTEM
  - INSTALL THIRD AFW PUMP (UPGRADE TO THIRD SAFETY-GRADE TRAIN IN NEXT OUTAGE)
- o NOVEMBER 21, 1985 WATER HAMMER EVENT
- o INCIDENT INVESTIGATION TEAM DISPATCHED TO SITE
- o LICENSEE BEGAN REFUELING OUTAGE EARLY

PAD#1:PWR-A:NRR
RICHARD DUDLEY
2/12/86

NRC STAFF ACTIONS TO RESOLVE LOSS OF POWER/WATER HAMMER CONCERNS

- IIT REPORT JANUARY 20, 1986
- IIT PRESENTATION TO COMMISSION; JANUARY 22, 1986
- EDO MEMO - FEBRUARY 4, 1986:
  - REGION V LEAD FOR FACILITY RESTART
  - NRR TO REVIEW TECHNICAL DESIGN QUESTIONS
  - IE GIVEN GENERIC LEAD RE: CHECK VALVE PROBLEMS AND GENERIC ADEQUACY OF IST
  - NRR TO ASSESS NEED TO REEVALUATE WATER HAMMER USI
- NRC TO MEET WITH SCE ON FEBRUARY 19, 1986, TO DISCUSS ITEMS REQUIRED FOR RESTART
- SCE TO MEET WITH COMMISSION IN MARCH 1986
- PLANT RESTART ORIGINALLY SCHEDULED FOR MAY 20, 1986

PAD#1:PWR-A:NRR
RICHARD DUDLEY
2/12/86

COMMISSION BRIEFING

LOSS OF POWER AND WATER HAMMER EVENT

SONGS 1

NOVEMBER 21, 1985

T. T. MARTIN 488 1280
JANUARY 22, 1986

/

SAN ONOFRE, UNIT 1 (SONGS-1)

- OPERATED BY SOUTHERN CALIFORNIA EDISON
- LOCATED SOUTH OF LOS ANGELES NEAR SAN CLEMENTE, CALIFORNIA
- WESTINGHOUSE 3-LOOP PWR
- LICENSED 1967
- 1337 MW_T / 450 MW_E
- SPHERICAL STEEL CONTAINMENT WITH CONCRETE ENCLOSURE BUILDING
- ELECTRIC MAIN FEEDWATER PUMPS ALSO FUNCTION AS SAFETY INJECTION PUMPS

T. T. MARTIN, 488 1280
JANUARY 22, 1986

SAN ONOFRE, UNIT 1 CONT'D

- 1 TURBINE AND 1 ELECTRIC AUXILIARY FEEDWATER PUMP
- 1 IMMEDIATE AND 1 DELAYED ACCESS OFFSITE POWER SOURCE
- DIESELS START, BUT DO NOT AUTOMATICALLY LOAD ON LOSS OF POWER

T. T. MARTIN, 488 1280
JANUARY 22, 1986

EVENT OVERVIEW

- LOSS OF IN-PLANT AC POWER
- INOPERABLE FEED PUMP CHECK VALVE LEADS TO RUPTURE OF CONDENSATE SYSTEM COMPONENT
- LOSS OF FEEDWATER
- MULTIPLE INOPERABLE FEEDWATER CHECK VALVES ALLOW BACKFLOW FROM ALL STEAM GENERATORS
- WATER HAMMER IN B FEED LINE CAUSES PIPING, PIPING SUPPORTS AND COMPONENT DAMAGE
- DAMAGED FEEDWATER CHECK VALVE DEVELOPS SIGNIFICANT STEAM-WATER LEAK
- PLANT SHUTDOWN AND COOLDOWN COMPLETED SAFELY

T. T. MARTIN, 488 1280
JANUARY 22, 1986

TEAM ESTABLISHED BY EDO ON NOVEMBER 22, 1985
IN CONFORMANCE WITH COMMISSION APPROVED
INCIDENT INVESTIGATION PROGRAM

CHARTER

- DETERMINE WHAT HAPPENED
- IDENTIFY PROBABLE CAUSES OF WHAT HAPPENED
- MAKE APPROPRIATE FINDINGS AND CONCLUSIONS TO FORM BASIS FOR POSSIBLE FOLLOW-ON ACTIONS

T. T. MARTIN, 488 1280
JANUARY 22, 1986

T E A M   M E M B E R S

THOMAS T. MARTIN, TEAM LEADER

MATTHEW CHIRAMAL

WILLIAM G. KENNEDY

WAYNE D. LANNING

ALECK W. SERKIZ

STEVEN K. SHOWE

T. T. MARTIN, 488 1280
JANUARY 22, 1986

FACT FINDING METHODOLOGY

- INTERVIEWS AND MEETINGS
- PLANT DATA
- PERSONNEL LOGS
- QUARANTINED EQUIPMENT
- OBSERVATIONS
- STATUS REPORTS

T. T. MARTIN, 488 1280
JANUARY 22, 1986

SEQUENCE OF EVENTS

- INITIAL CONDITIONS
  - SMALL SALTWATER LEAK INTO MAIN CONDENSER
  - UNIT OPERATING AT 60 PERCENT POWER
  - STEAM GENERATOR BLOWDOWN ABOUT 100 GPM/STEAM GENERATOR
  - CRITICAL FUNCTION MONITOR SYSTEM DISABLED
  - ELECTRICAL GROUND TROUBLESHOOTING IN PROGRESS
  - ELECTRIC PLANT IN UNUSUAL ALIGNMENT

T. T. MARTIN, 488 1280
JANUARY 22, 1986

SEQUENCE OF EVENTS

°	T=0 (MIN)	AUXILIARY TRANSFORMER C ISOLATES (PARTIAL LOSS OF AC POWER)
°	$T=0^+$	ENS PHONE RINGS FEEDWATER PUMP CHECK VALVE FAILS TO CLOSE FLASH EVAPORATOR TUBE RUPTURES DIESEL GENERATOR 2 STARTS, BUT BY DESIGN DOES NOT LOAD
°	T=1/3	OPERATORS TRIP REACTOR AND UNIT GENERATOR (TOTAL LOSS OF INPLANT A/C POWER) CONTAINMENT ISOLATES DIESEL GENERATOR 1 STARTS, BUT BY DESIGN DOES NOT LOAD TURBINE-DRIVEN AUXILIARY FEEDWATER PUMP RECEIVES START SIGNAL FOUR ADDITIONAL FEEDWATER CHECK VALVES INOPERABLE

T. T. MARTIN, 488 1280
JANUARY 22, 1986

SEQUENCE OF EVENTS

° T=1/3+ FEEDWATER LINES BEGIN TO EMPTY

STEAM GENERATORS BEGIN TO LOSE INVENTORY VIA FAILED CHECK VALVES AND RUPTURED TUBE IN FLASH EVAPORATOR

LOSS OF VOLTAGE AUTOMATIC TRANSFER SCHEME INITIATED

ALARMS INDICATE SAFETY INJECTION ACTUATION

° T=3 FIRE TRUCK ARRIVES ON SITE

T. T. MARTIN, 488 1280
JANUARY 22, 1986

SEQUENCE OF EVENTS

- ° T=4 OPERATORS ATTEMPT TO RESTORE POWER

  TURBINE-DRIVEN AFW FLOW ABOUT 130 GPM/ STEAM GENERATOR

- ° $T=4^+$ OPERATORS RESTORE POWER ON FIFTH ATTEMPT

  MOTOR-DRIVEN AFW PUMP STARTS INCREASING FLOW TO 155 GPM/SG
  ATMOSPHERIC STEAM DUMPS OPEN

  OPERATORS CLOSE FEEDWATER ISOLATION VALVES

  RADIATION MONITOR ALARMS RESET (S/G BLOWDOWN RE-ESTABLISHED)

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JANUARY 22, 1986

SEQUENCE OF EVENTS

- T=6 RCS PRESSURE, TEMPERATURE AND PRESSURIZER LEVEL INDICATE RAPID COOLDOWN
- T=7 OPERATORS START CHARGING PUMP SECOND PUMP AUTO STARTS LATER
- T=10 REACTOR COOLANT PUMP B STARTED
- T=11 OPERATORS TERMINATE (10 SECONDS) AND RE-ESTABLISH AUXILIARY FEEDWATER FLOW AT 40 GPM/SG
- T=15 UNUSUAL EVENT DECLARED ONSITE/NOT TO NRC

T. T. MARTIN, 488 1280
JANUARY 22, 1986

SEQUENCE OF EVENTS

° T=16 WATER HAMMER OCCURRED

° T=18 RCP B THRUST BEARING HIGH TEMPERATURE ALARM

° T=19 PLANT EQUIPMENT OPERATOR INFORMS CONTROL ROOM OF "STEAMLINE BREAK"

° T=25 CONTAINMENT COOLING RE-ESTABLISHED

° T=29 OPERATORS SECURE DIESEL GENERATORS
OPERATORS SECURE LUBE OIL RESERVOIR FOAM SYSTEM

T. T. MARTIN, 488 1280
JANUARY 22, 1986

SEQUENCE OF EVENTS

- T=33 RCP A STARTED
- T=36 RCP C STARTED
  STEAM GENERATOR LEVELS OFF-SCALE LOW
- T=37 RCP B STOPPED
  AFW FLOW TO A AND C INCREASED TO 70 GPM/SG
  TO ESTABLISH RAPID BUT ACCEPTABLE COOLDOWN
- T=39 STEAM GENERATOR BLOWDOWN DISCOVERED AND
  TERMINATED
- T=40 STEAM GENERATOR A AND C LEVELS ONSCALE
  ATTEMPTS BEGIN TO IDENTIFY STEAM LEAK

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JANUARY 22, 1986

SEQUENCE OF EVENTS

°	T=90 (MIN)	OPERATORS UNABLE TO START CIRCULATING WATER PUMP
°	T=3 (HR)	ENTERED MODE 4
°	T=4	OPERATOR OVERRODE RHR INTERLOCK
°	T=5	UNUSUAL EVENT TERMINATED
°	T=6	FEEDWATER LEAKAGE ISOLATED
°	T=10	ENTERED MODE 5

T. T. MARTIN, 488 1280
JANUARY 22, 1986

SEQUENCE OF EVENTS

NOVEMBER 22	CONTAINMENT ENTRY FOUND EVIDENCE OF WATER HAMMER DAMAGE

T. T. MARTIN, 488 1280
JANUARY 22, 1986

PERSONNEL PERFORMANCE EVALUATIONS

- OPERATOR ERRORS
  - FAILED TO FOLLOW APPROPRIATE PROCEDURES WHEN TROUBLESHOOTING ELECTRICAL GROUND
  - DIFFICULTY IN RE-ESTABLISHING INPLANT POWER
  - INADVERTENTLY RE-ESTABLISHED STEAM GENERATOR BLOWDOWN
  - DID NOT RESET FOX III COMPUTER
- STA PERFORMANCE GOOD
- EMERGENCY COORDINATOR PERFORMANCE ERRORS
- NRC-LICENSEE COMMUNICATIONS WERE NOT EFFECTIVE

T. T. MARTIN, 488 1280
JANUARY 22, 1986

EQUIPMENT PROBLEMS

ITEM		NATURE OF FAILURE	PROBABLE ROOT CAUSE	COMMENTS
1.	POWER SUPPLY CABLE	GROUND FAULT	WATER INLEAKAGE	ANALYSES ONGOING
2.	FLASH EVAPORATOR UNIT	TUBE/SHELL RUPTURED	OVERPRESSURIZED DUE TO FAILED CHECK VALVE	NO LONGER USED
3.	SAFETY INJECTION ANNUNCIATOR	SPURIOUS ALARM	LOSS OF POWER	DESIGN INADEQUACY
4.	SAFEGUARD LOAD SEQUENCING SYSTEM	INDICATED SAFETY INJECTION ACTUATION	NOT IDENTIFIED	ANALYSES ONGOING
5.	LOSS OF VOLTAGE AUTO TRANSFER SCHEME	FAILED TO REALIGN CIRCUIT BREAKERS TO RESTORE POWER	NOT IDENTIFIED	ANALYSES ONGOING

T. T. MARTIN, 488 1280
JANUARY 22, 1986

EQUIPMENT PROBLEMS CONT'D

ITEM		NATURE OF FAILURE	PROBABLE ROOT CAUSE	COMMENTS
6.	FOX III COMPUTER	NO RECORDED DATA BEFORE/AFTER TRIP	POWER INTERRUPTION	RESET REQUIRED
7.	TURBINE RUPTURE DISKS (4 OF 8)	RUPTURED	OVERPRESSURIZED DUE TO LOSS OF POWER	EXPECTED
8.	EMERGENCY NOTIFICATION SYSTEM	SPURIOUS RINGS	NOT IDENTIFIED	CANNOT REPRODUCE
9.	RCP THRUST BEARING	HIGH TEMPERATURE ALARM	FAILED DETECTOR	
10.	CHECK VALVE FWS-378	STUDS STRETCHED BODY TO BONNET LEAK	WATER HAMMER	

T. T. MARTIN, 488 1280
JANUARY 22, 1986

EQUIPMENT PROBLEMS CONT'D

ITEM	NATURE OF FAILURE	PROBABLE ROOT CAUSE	COMMENTS
11. CHECK VALVE FWS-345	NUT MISSING DISC SEPARATED FROM HINGE ARM	NOT IDENTIFIED	EVALUATION ONGOING
12. CHECK VALVE FWS-346	NUT MISSING DISC SEPARATED FROM HINGE ARM	NOT IDENTIFIED	EVALUATION ONGOING
13. CHECK VALVE FWS-398	NUT LOOSE STUCK-OPEN	NOT IDENTIFIED	EVALUATION ONGOING
14. CHECK VALVE FWS-438	NUT LOOSE STUCK-OPEN	NOT IDENTIFIED	NOT PINNED EVALUATION ONGOING

T. T. MARTIN, 488 1280
JANUARY 22, 1986

EQUIPMENT PROBLEMS CONT'D

ITEM	NATURE OF FAILURE	PROBABLE ROOT CAUSE	COMMENTS
15. CHECK VALVE FWS-439	NUT LOOSE STUCK-OPEN	NOT IDENTIFIED	NOT PINNED EVALUATION ONGOING
16. FLOW CONTROL VALVE FCV-457	BROKEN YOKE BENT STEM	WATER HAMMER	INERTIA
17. B STEAM GENERATOR FEEDWATER LINE	CRACKED BENT DENTED	WATER HAMMER	EVALUATION ONGOING BEING REMOVED MOST SUSCEPTIBLE PIPING
18. FEEDWATER LINE SUPPORTS & SNUBBERS	DAMAGED	WATER HAMMER	EVALUATION ONGOING

T. T. MARTIN, 488 1280
JANUARY 22, 1986

EQUIPMENT PROBLEMS CONT'D

ITEM	NATURE OF FAILURE	PROBABLE ROOT CAUSE	COMMENTS
19. AUXILIARY FEEDWATER LINE SUPPORTS	DISPLACEMENT	WATER HAMMER	
20. CONTAINMENT SPHERE	SMALL CRACK-LIKE INDICATIONS	NOT IDENTIFIED	EVALUATION ONGOING
21. SECURITY ACCESS CONTROLS	SECURE	SAFEGUARDS INFORMATION	NO SAFETY/SAFE-GUARDS INTERFACE PROBLEM

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PRINCIPAL FINDINGS AND CONCLUSIONS

THE EVENT WAS SIGNIFICANT

- ALL INPLANT AC POWER WAS LOST FOR FOUR MINUTES
- ALL STEAM GENERATOR FEEDWATER WAS LOST FOR THREE MINUTES
- A SEVERE WATER HAMMER WAS EXPERIENCED IN THE FEEDWATER SYSTEM
  - CAUSED A LEAK
  - DAMAGED PLANT EQUIPMENT
  - CHALLENGED THE INTEGRITY OF THE ULTIMATE HEAT SINK
- ALL INDICATED STEAM GENERATOR WATER LEVELS DROPPED BELOW SCALE
- THE REACTOR COOLANT SYSTEM EXPERIENCED AN ACCEPTABLE BUT UNNECESSARY COOLDOWN TRANSIENT

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SIGNIFICANT FINDINGS

(NOT NECESSARILY IN ORDER OF THEIR SIGNIFICANCE)

1. THE PRIMARY CAUSE FOR THE WATER HAMMER IN THE FEEDWATER PIPING WAS THE FAILURE OF MULTIPLE CHECK VALVES IN THE FEEDWATER SYSTEM. THESE FAILURES PERMITTED THE PIPING TO EMPTY AND FILL WITH STEAM BEFORE THE MOTOR-OPERATED FEEDWATER ISOLATION VALVES WERE CLOSED. ALTHOUGH THE STEAM CONDENSATION-INDUCED WATER HAMMER OCCURRED IN ONLY ONE FEEDWATER LINE, THE POTENTIAL EXISTED FOR WATER HAMMER TO OCCUR THROUGHOUT THE SAFETY-RELATED PORTIONS OF THE FEEDWATER SYSTEM.

2. THE FAILURES OF THE FIVE CHECK VALVES IN THE FEEDWATER SYSTEM PROVIDED A MECHANISM FOR POTENTIAL COMMON MODE FAILURE OF THE HEAT SINK PROVIDED BY THE THREE STEAM GENERATORS. THE FAILED CHECK VALVES PERMITTED HIGH PRESSURE STEAM AND WATER FROM THE STEAM GENERATORS TO FLOW BACK TO THE LOW PRESSURE CONDENSATE SYSTEM; THE BACKFLOW CARRIED WITH IT THE AUXILIARY FEEDWATER FLOW NECESSARY TO MAINTAIN THE HEAT SINK PROVIDED BY THE STEAM GENERATORS. OPERATOR ACTIONS WERE NECESSARY TO STOP THE BACKLEAKAGE AND PREVENT A MORE SERIOUS SEQUENCE OF EVENTS.

3. LONG HORIZONTAL RUNS OF FEEDWATER PIPING WITH THE POTENTIAL FOR VOIDING ARE PARTICULARLY SUSCEPTIBLE TO DESTRUCTIVE STEAM CONDENSATION-INDUCED WATER HAMMERS. FURTHER, OPERATORS ARE NOT PROVIDED THE MEANS FOR DETECTING THE VOIDING OF THESE LINES OR GIVEN GUIDANCE ON APPROPRIATE WAYS TO DEAL WITH THE SITUATION. DESIGN OR PROCEDURAL CHANGES MAY BE WARRANTED.

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SIGNIFICANT FINDINGS CONT'D

4. THE FLASH EVAPORATOR FAILED WHEN OVERPRESSURIZED BY THE DISCHARGE FLOW OF AN OPERATING FEEDWATER PUMP DUE TO THE PARTIAL LOSS OF POWER AND A STUCK OPEN FEEDWATER PUMP DISCHARGE CHECK VALVE THAT SHOULD HAVE PREVENTED THE BACKFLOW.

5. THE TIMING OF THE FIVE CHECK VALVE FAILURES COULD NOT BE ASCERTAINED WITH CERTAINTY. THE TEAM CONCLUDED THAT ALL CHECK VALVES HAD FAILED PRIOR TO THE EVENT BECAUSE THE MISSING PARTS TO THE VALVES WERE NOT FOUND IN THE INSPECTED FEEDWATER PIPING AFTER THE EVENT. NOISE FROM THE B STEAM GENERATOR FEEDWATER PIPING, EVIDENT TO PLANT PERSONNEL SINCE JUNE 24, 1985, SUPPORTS THE CONCLUSION THAT THE FEEDWATER CONTROL STATION CHECK VALVE IN THE B FEEDWATER LINE HAD FAILED EARLIER. THE INSPECTION OF THE STEAM GENERATORS HAS NOT YET BEEN COMPLETED BY SCE.

6. THE SURVEILLANCE PROCEDURE FOR TESTING THE CHECK VALVES I.. THE INSERVICE TESTING (IST) PROGRAM LACKED ADEQUATE METHODS AND OBJECTIVE ACCEPTANCE CRITERIA FOR DETERMINING WHETHER CHECK VALVES ARE CLOSED. THUS, ALTHOUGH THE CHECK VALVES HAD BEEN TESTED WITHIN THE PAST YEAR, OPERATORS MAY HAVE MISINTERPRETED THE TEST RESULTS. FURTHERMORE, THE IST IS NOT DESIGNED TO DETECT DEVELOPING CONDITIONS THAT MAY LEAD TO THE FAILURE OF THE CHECK VALVES; E.G., LOOSE DISKS AND STUD NUTS.

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SIGNIFICANT FINDINGS CONT'D

7. THE NRC HAD NOT COMPLETED ITS REVIEW OF SCE'S INSERVICE TESTING PROGRAM. THE INITIAL PROGRAM WAS SUBMITTED IN SEPTEMBER 1977 AND REVISED IN ITS ENTIRETY ON JANUARY 24, 1984. DISAGREEMENT BETWEEN SCE AND NRC ON RESOLUTION OF CERTAIN OPEN ISSUES AND SCHEDULING PROBLEMS WITH NRC'S REVIEW HAVE SUBSTANTIVELY CONTRIBUTED TO THIS DELAY.

8. THE RESOLUTION OF THE UNRESOLVED SAFETY ISSUE, USI A-1, "WATER HAMMER," DID NOT SPECIFICALLY ADDRESS THE PREVENTION AND MITIGATION OF THE CONSEQUENCES OF CONDENSATION- INDUCED WATER HAMMERS IN FEEDWATER PIPING UPSTREAM OF THE FEEDRING. INTERVIEWS OF NRC STAFF INVOLVED IN RESOLUTION OF WATER HAMMER ISSUES FAILED TO DEVELOP CITABLE REFERENCES, DECISIONS, OR DISCUSSIONS THAT PROVIDED A BASIS FOR EXCLUDING FURTHER CONSIDERATION OF FEEDWATER PIPING WATER HAMMER. HOWEVER, IN THE REGULATORY ANALYSIS OF THE RESOLUTION OF USI A-1, THE STAFF ACKNOWLEDGED THAT ELIMINATION OF WATER HAMMERS IS NOT FEASIBLE, THAT THE FREQUENCY OF WATER HAMMERS HAD BEEN SUBSTANTIALLY REDUCED BY CHANGES IN DESIGN AND OPERATIONS, AND THAT STUDIES OF WATER HAMMER HAD REVEALED A SIGNIFICANTLY LESSER SAFETY CONCERN THAN PREVIOUSLY HYPOTHESIZED. IT APPEARS THAT FURTHER CONSIDERATION OF WATER HAMMERS DUE TO MAIN FEEDWATER LINE VOIDING WAS NOT PURSUED DUE TO A LACK OF REPORTED OCCURRENCES IN U.S. PLANTS.

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SIGNIFICANT FINDINGS CONT'D

9. NRC'S RELIANCE ON "J" TUBES TO DELAY THE DEVELOPMENT OF CONDITIONS NECESSARY TO SUPPORT STEAM GENERATOR WATER HAMMER IMPLICITLY ASSUMES THAT FEEDWATER CHECK VALVE INTEGRITY WOULD BE MAINTAINED TO PREVENT STEAM GENERATOR FEEDRING VOIDING. HOWEVER, CORRESPONDING REGULATORY REQUIREMENTS TO ENSURE THAT THESE CHECK VALVES PERFORMED THIS SAFETY FUNCTION WERE NOT PART OF THE RESOLUTION OF THE WATER HAMMER ISSUE.

10. THE ROOT CAUSE FOR THE LOSS OF POWER WAS A PHASE-TO-PHASE FAULT OF AN ELECTRICAL CABLE FROM AUXILIARY TRANSFORMER C TO BUS 1C. THE UNDERLYING REASON FOR THE CABLE FAILURE HAS NOT YET BEEN DETERMINED; HOWEVER, IT APPEARS THAT THE CABLE MAY HAVE BECOME WETTED BY A LONG-TERM FLANGE LEAK FROM THE FEEDWATER SYSTEM, RUNNING ABOVE THE CABLE TRAY.

11. THE PLANT IS DESIGNED TO EXPERIENCE AN EXTENDED LOSS OF INPLANT AC POWER ON LOSS OF OFFSITE POWER WITHOUT SAFETY INJECTION. OPERATORS ARE REQUIRED TO RESTORE POWER FROM THE SWITCHYARD OR TO LOAD THE DIESEL GENERATORS TO RESTORE INPLANT POWER. SCE'S EMERGENCY OPERATING INSTRUCTIONS ON LOSS OF AC POWER LACK GUIDANCE ON HOW LONG OPERATORS CAN ATTEMPT TO RESTORE POWER FROM OFFSITE SOURCES BEFORE THE DIESEL GENERATORS SHOULD BE LOADED FOLLOWING A LOSS OF INPLANT AC POWER, OR HOW LONG THE DIESEL GENERATORS CAN RUN UNLOADED WITHOUT OVERHEATING, IF THEIR AC-POWERED RADIATOR FANS REMAIN DE-ENERGIZED.

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SIGNIFICANT FINDINGS CONT'D

12. THE STATION LOSS OF VOLTAGE AUTO TRANSFER SCHEME FOR ESTABLISHING THE DELAYED ACCESS TO OFFSITE POWER MAY NOT HAVE FUNCTIONED AS DESIGNED. SCE EVALUATIONS ARE CONTINUING.

13. THE MULTIPLE SPURIOUS INDICATIONS EARLY IN THE EVENT THAT A SAFETY INJECTION ACTUATION HAD OCCURRED, ADDED TO THE CONFUSION OF THE SITUATION AND UNNECESSARILY INCREASED THE BURDEN ON THE OPERATORS. OPERATORS DIAGNOSED PLANT CONDITIONS AND APPROPRIATELY DISREGARDED THESE INDICATIONS. THE SAFETY INJECTION ANNUNCIATOR WILL ALWAYS INCORRECTLY ALARM ON A LOSS OF AC POWER. THIS IS A DESIGN DEFICIENCY. THE CAUSE OF THE SPURIOUS INDICATION ON BOTH SAFEGUARD LOAD SEQUENCER SYSTEM PANELS IS STILL UNKNOWN.

14. THE OPERATING STAFF, WITH THE CONCURRENCE OF MANAGEMENT, DID NOT FOLLOW APPROPRIATE PROCEDURES WHEN TROUBLESHOOTING THE ELECTRICAL GROUND. THEIR ACTIONS UNNECESSARILY DELAYED ENTRY INTO TECHNICAL SPECIFICATION ACTION STATEMENT REQUIREMENTS THAT COULD REQUIRE PLANT SHUTDOWN.

15. ONCE THE ELECTRICAL GROUND WAS LOCATED ON THE FEEDER FROM AUXILIARY TRANSFORMER C TO BUS 1C, THE OPERATORS DID NOT AGGRESSIVELY PURSUE ISOLATING THE AUXILIARY TRANSFORMER. INSTEAD, THEY OPTED TO LEAVE THE TRANSFORMER ENERGIZED WHILE TECHNICIANS PERFORMED INSPECTIONS THAT DID NOT REQUIRE THE TRANSFORMER TO BE ENERGIZED.

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SIGNIFICANT FINDINGS CONT'D

16. THE OPERATORS' ACTIONS AFTER THE TRANSFORMER TRIP WERE CONSISTENT WITH THEIR TRAINING. HOWEVER, IN THE TEAM'S JUDGMENT, SOME OPERATORS, LACKED DETAILED PLANT KNOWLEDGE IN THE FOLLOWING AREAS:

   ° CAUTIONS ASSOCIATED WITH PARALLELING TRANSFORMERS

   ° REQUIREMENTS FOR RESETTING UNIT GENERATOR TRIPS

   ° THE PROCESS FOR OPERATING 220KV CIRCUIT BREAKERS

   ° EXPECTED INDICATIONS AND TIMING OF THE LOSS OF VOLTAGE AUTOMATIC TRANSFER SCHEME

   ° SETPOINTS FOR RESIDUAL HEAT REMOVAL SYSTEM PRESSURE INTERLOCK

   ° EXPECTED INDICATION AND MEANING OF LIGHTS ON SLSS SEQUENCER PANELS

   ° OPERABILITY OF DIESEL GENERATORS WITH AUXILIARY TRANSFORMER C REACTOR COIL BYPASS BREAKERS REMOVED.

THESE DEFICIENCIES MAY BE DUE TO INADEQUATE OPERATOR TRAINING AND/OR PROCEDURES.

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SIGNIFICANT FINDINGS CONT'D

17. ON OCCASION, SOME SITE PERSONNEL WHO GENERALLY EVALUATE PLANT DATA LACKED A SUFFICIENTLY INQUIRING ATTITUDE. AS A RESULT, CERTAIN SIGNIFICANT INDICATIONS OF UNDERLYING REASONS FOR SYSTEM RESPONSE OR COMPONENT PERFORMANCE WERE NOT DETECTED UNTIL BROUGHT TO THE ATTENTION OF SCE BY THE TEAM. IT APPEARS THAT SCE'S PROCESS FOR EVALUATING AND FOLLOWING UP EVENTS MAY NOT BE SUFFICIENTLY THOROUGH AND SYSTEMATIC TO ASSURE THAT FAILED COMPONENTS ARE DETECTED AND ADEQUATELY EXPLAINED.

18. THE STATUS OF THE STEAM GENERATOR BLOWDOWN SYSTEM IS NOT INDICATED IN THE CONTROL ROOM. THE REESTABLISHMENT OF BLOWDOWN WHEN THE RADIATION MONITORS WERE RESET WAS NOT RECOGNIZED AND ADVERSELY CONTRIBUTED TO THE COOLDOWN OF THE REACTOR COOLANT SYSTEM AND TO THE DELAY IN RECOVERING THE STEAM GENERATOR LEVELS.

19. DURING THE LOSS OF ALL INPLANT AC POWER, SUFFICIENT INFORMATION WAS AVAILABLE IN THE CONTROL ROOM TO ENABLE THE OPERATORS TO FOLLOW THEIR PROCEDURES AND ENSURE PLANT SAFETY. HOWEVER, CONTROL ROOM OPERATORS HAD FAILED TO HAVE THE TECHNICAL SUPPORT CENTER COMPUTER RESET FOLLOWING ELECTRICAL GROUND TROUBLESHOOTING ACTIVITIES. THIS FAILURE DISABLED THE COMPUTER'S ABILITY TO RECORD NEW PLANT DATA AND THEREBY DENIED THE OPERATORS ACCESS TO PRE-TRIP AND POST-TRIP TRENDS THAT WOULD HAVE ASSISTED REAL TIME AND POST-EVENT ANALYSIS AND EVALUATION. HAD THE STATION BLACKOUT BEEN OF LONGER DURATION, OR INVOLVED ADDITIONAL COMPLICATIONS, OPERATOR RESPONSES AND THE FUNCTIONS PROVIDED BY THE TECHNICAL SUPPORT CENTER COULD HAVE BEEN HAMPERED BY THE LACK OF TREND DATA.

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SIGNIFICANT FINDINGS CONT'D

20. STATION MAINTENANCE RECORDS ARE INCOMPLETE, DIFFICULT TO LOCATE AND, WHEN AVAILABLE, LACK SUFFICIENT DETAIL TO DETERMINE WHAT WAS DONE.

21. THE SPURIOUS RINGING OF THE NRC RED PHONE AT THE BEGINNING OF THE EVENT HAS NOT BEEN EXPLAINED, BUT IT DISTRACTED CONTROL ROOM PERSONNEL AND CONTRIBUTED TO THE CONFUSION IN THE COMMUNICATIONS BETWEEN SCE AND NRC.

22. ENS COMMUNICATIONS BETWEEN NRC AND SCE WERE NOT EFFECTIVE BECAUSE: (1) THE NRC DUTY OFFICER WAS NOT KNOWLEDGEABLE ABOUT THE UNIQUE DESIGN OF THE PLANT AND, THEREFORE, MISINTERPRETED OPERATOR RESPONSES TO QUESTIONS; (2) COMMUNICATIONS WITH THE PLANT WERE INITIALLY LIMITED BECAUSE STATEMENTS BY PLANT OPERATORS INCORRECTLY IMPLIED THAT SUFFICIENT PERSONNEL WERE NOT AVAILABLE TO SUPPORT THE ESTABLISHMENT OF AN OPEN LINE; (3) NRC ASKED LEADING QUESTIONS AND OPERATORS SOMETIMES DID NOT CORRECT, AND IN SOME CASES APPEARED TO CONFIRM, INACCURATE INFORMATION; (4) NRC QUESTIONS CHARACTERISTICALLY FOCUSED ON DETAILS RATHER THAN ON THE "BIG PICTURE"; (5) NRC CLUTTERED THE COMMUNICATIONS CHANNEL WITH REPETITIVE DISCUSSIONS ABOUT THE SEQUENCE OF EVENTS AS ADDITIONAL NRC PERSONNEL CAME ON THE LINE TO THE EXCLUSION OF OBTAINING NEW PLANT INFORMATION; (6) NRC RESIDENT INSPECTORS RELIEVED MORE KNOWLEDGEABLE PLANT OPERATORS AS ENS COMMUNICATORS AND REESTABLISHED THE COMMUNICATIONS AT A LOCATION REMOTE FROM REAL TIME PLANT INFORMATION; AND, (7) PLANT OPERATORS FAILED TO INFORM THE NRC OF THE DECLARATION OF AN UNUSUAL EVENT.

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SIGNIFICANT FINDINGS CONT'D

23. THERE WERE TWO MALFUNCTIONS OF THE AUTOMATED SECURITY ACCESS CONTROL EQUIPMENT; HOWEVER, SITE PERSONNEL IMPLEMENTED APPPOPRIATE PLANNED COMPENSATORY MEASURES, THEREBY PRECLUDING A SAFETY-SAFEGUARDS INTERFACE PROBLEM.

24. THERE WAS NO SIGNIFICANT RELEASE OF RADIOACTIVITY.

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CONCLUSION

THE MOST SIGNIFICANT ASPECT OF THE EVENT WAS THAT FIVE SAFETY-RELATED FEEDWATER SYSTEM CHECK VALVES DEGRADED TO THE POINT OF INOPERABILITY DURING A PERIOD OF LESS THAN A YEAR, WITHOUT DETECTION, AND THAT THEIR FAILURE JEOPARDIZED THE INTEGRITY OF SAFETY-RELATED FEEDWATER PIPING.

- THE ROOT CAUSES OF THE CHECK VALVE FAILURES HAVE NOT BEEN DETERMINED AND ARE STILL UNDER REVIEW BY SCE AND ITS CONTRACTORS
- POTENTIAL CONTRIBUTORS TO THIS PROBLEM INCLUDE INADEQUATE MAINTENANCE, INADEQUATE INSERVICE TESTING, INADEQUATE DESIGN, AND INADEQUATE CONSIDERATION OF THE EFFECTS OF REDUCED POWER OPERATIONS.

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POTENTIAL CONTRIBUTORS TO FAILURES

- MAINTENANCE RECORDS FOR THESE VALVES WERE EITHER MISSING OR LACKED SPECIFICITY ON WHAT WAS DONE

- INSERVICE TESTING RECORDS FOR THESE VALVES WERE INCONSISTENT; THE TESTING PROCEDURE WAS NOT RIGOROUS; THE TEST ACCEPTANCE CRITERIA WERE SUBJECTIVE; THE TESTING FREQUENCY WAS OPEN-ENDED; AND, THE TEST DID NOT ASSURE DETECTION OF THE FAILURES FOUND.

- THESE CHECK VALVES AND VALVES OF SIMILAR DESIGN HAVE A HISTORY OF LIKE FAILURES

- REDUCED POWER OPERATIONS AT UNIT 1 ARE NOW ROUTINE BECAUSE OF STEAM GENERATOR TUBE PLUGGING AND SLEEVING, AND THE REDUCED FEEDWATER FLOW MAY HAVE INCREASED THE SUSCEPTIBILITY OF CHECK VALVE COMPONENTS TO HYDRAULIC-INDUCED VIBRATION.

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JANUARY 22, 1986

AGENDA

MEETING WITH ACRS

SAN ONOFRE UNIT 1

WATER HAMMER EVENT OF NOVEMBER 21, 1985

FEBRUARY 12, 1986

INTRODUCTION

WATER HAMMER EVENT

FEEDWATER CHECK VALVES

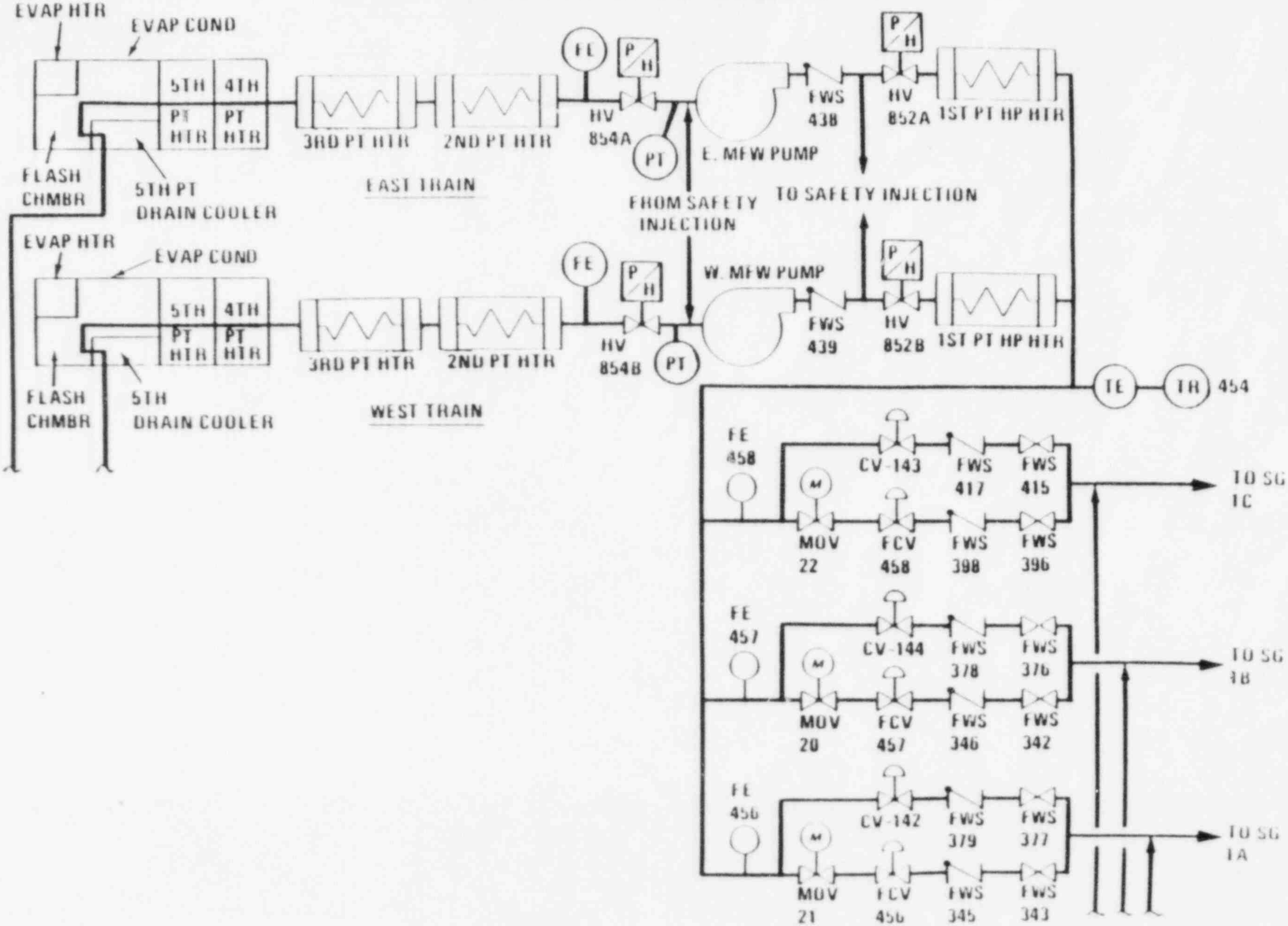
CORRECTIVE ACTIONS

CONCLUSIONS

INTRODUCTION

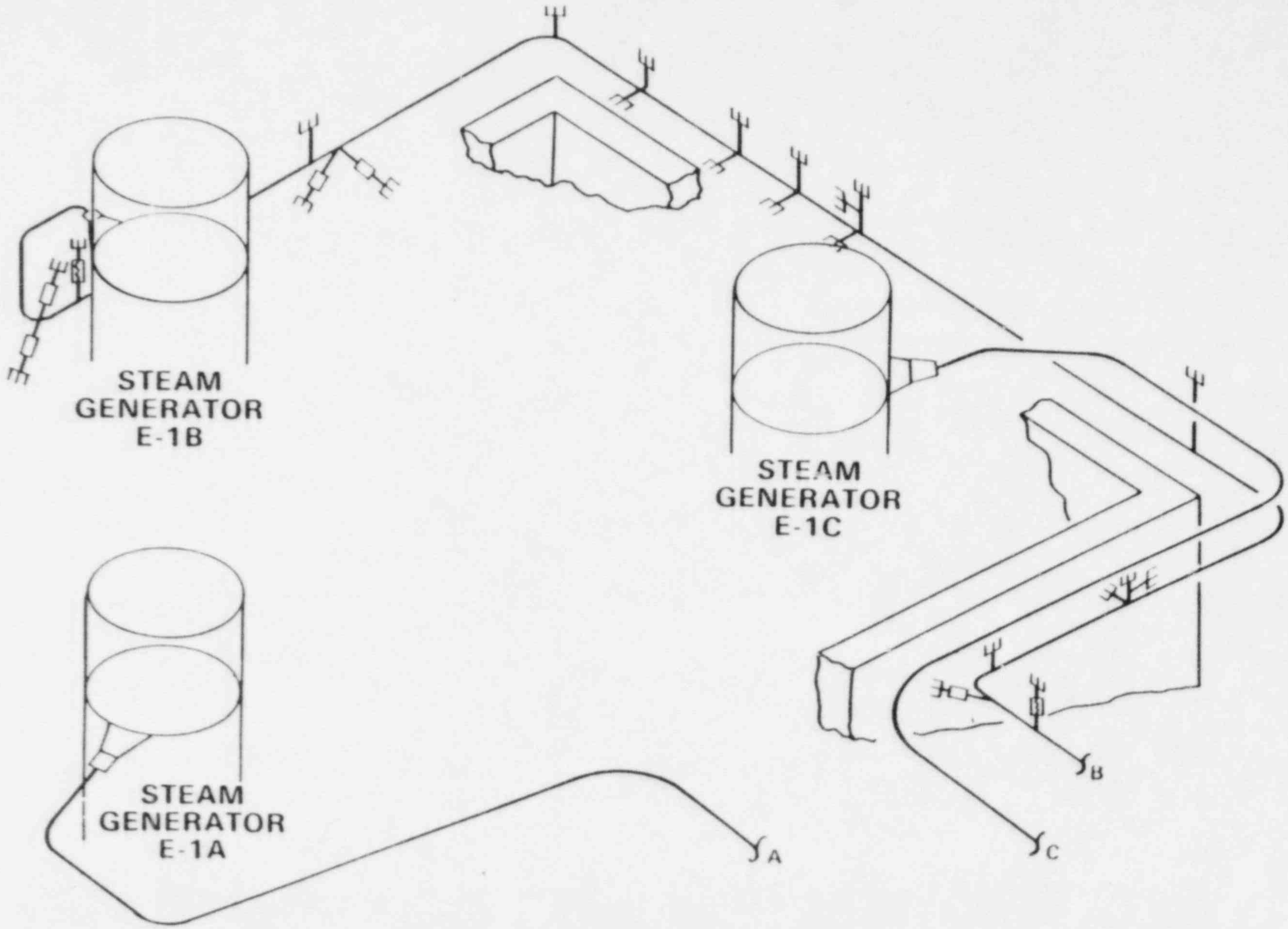
- o EVENT WAS VERY SIGNIFICANT
- o MOST SIGNIFICANT ASPECT OF EVENT IS FAILURE OF FIVE FEEDWATER CHECK VALVES

MAIN AND AUXILIARY FEEDWATER
SAN ONOFRE UNIT 1



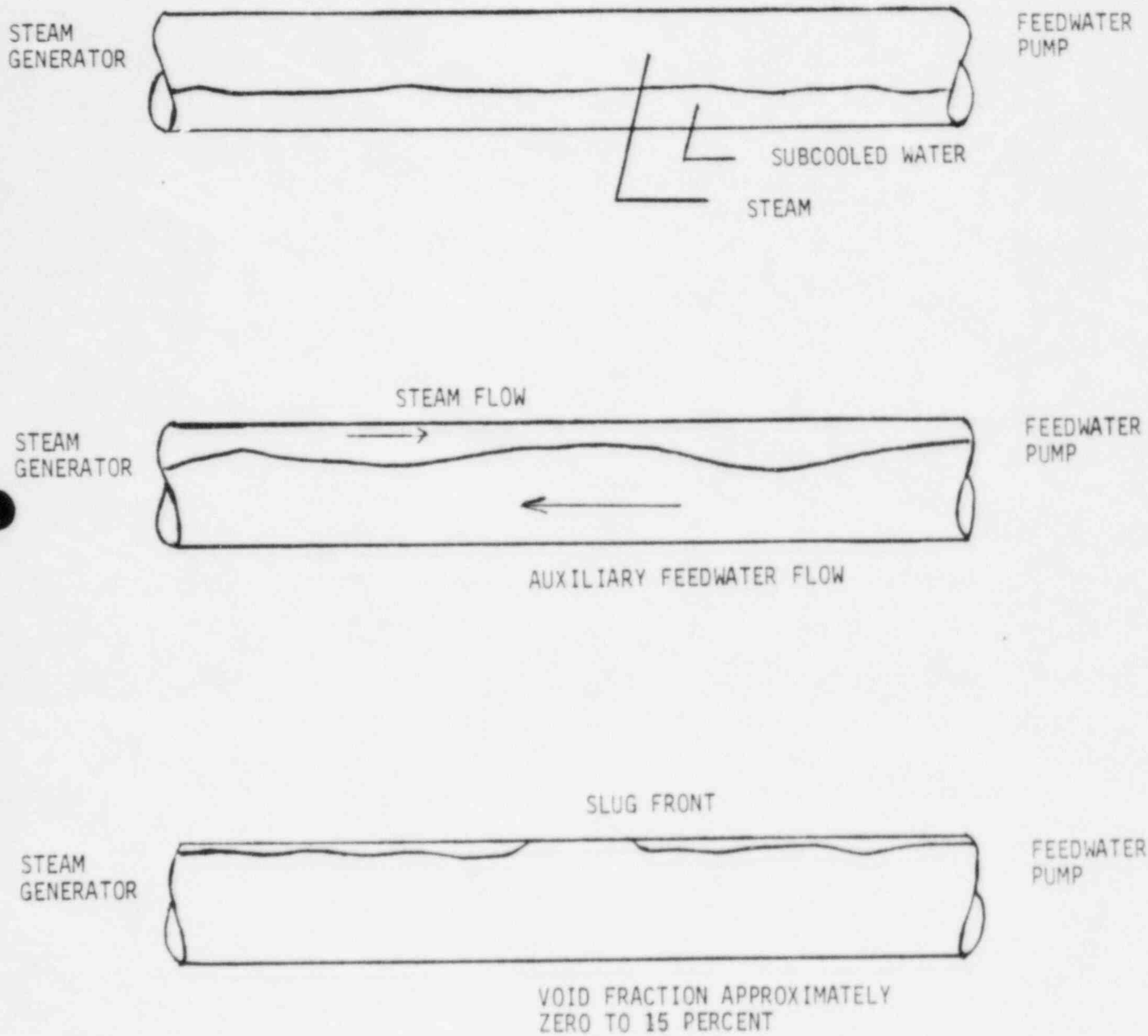
MAIN FEEDWATER WATER HAMMER EVENT

- EAST FEEDWATER PUMP LOSES POWER (0000)
- EAST FEEDWATER PUMP DISCHARGE CHECK VALVE (FWS-438) ALLOWS REVERSE FLOW
- LOUD NOISE HEARD IN AREA OF EAST FEEDWATER EVAPORATOR CONDENSER
- WEST FEEDWATER PUMP LOSES POWER (0001)
- FEEDWATER CHECK VALVES (FWS-398,-345 & -346) ALLOW LINES TO VOID
- AUXILIARY FEEDWATER FLOW INITIATED AT 100 GPM (0004)
- COMBINED AFW FLOW CONTROLLED TO 135-150 GPM (0008)
- MAIN FEEDWATER FLOW CONTROL VALVES AND MOTOR OPERATED BLOCK VALVES SHUT IN ACCORDANCE WITH EMERGENCY OPERATING INSTRUCTION (0008)
- FEEDWATER LINES 'A' AND 'C' REFILL
- AUXILIARY FEEDWATER FLOW REDUCED TO ZERO THEN INCREASED TO 25-40 GPM (0009)
- WATER HAMMER EVENT EXPERIENCED (0020)


STEAM GENERATOR E-1B
STEAM GENERATOR E-1C
STEAM GENERATOR E-1A
A
B
C

TYPICAL WATER SLUG MODEL

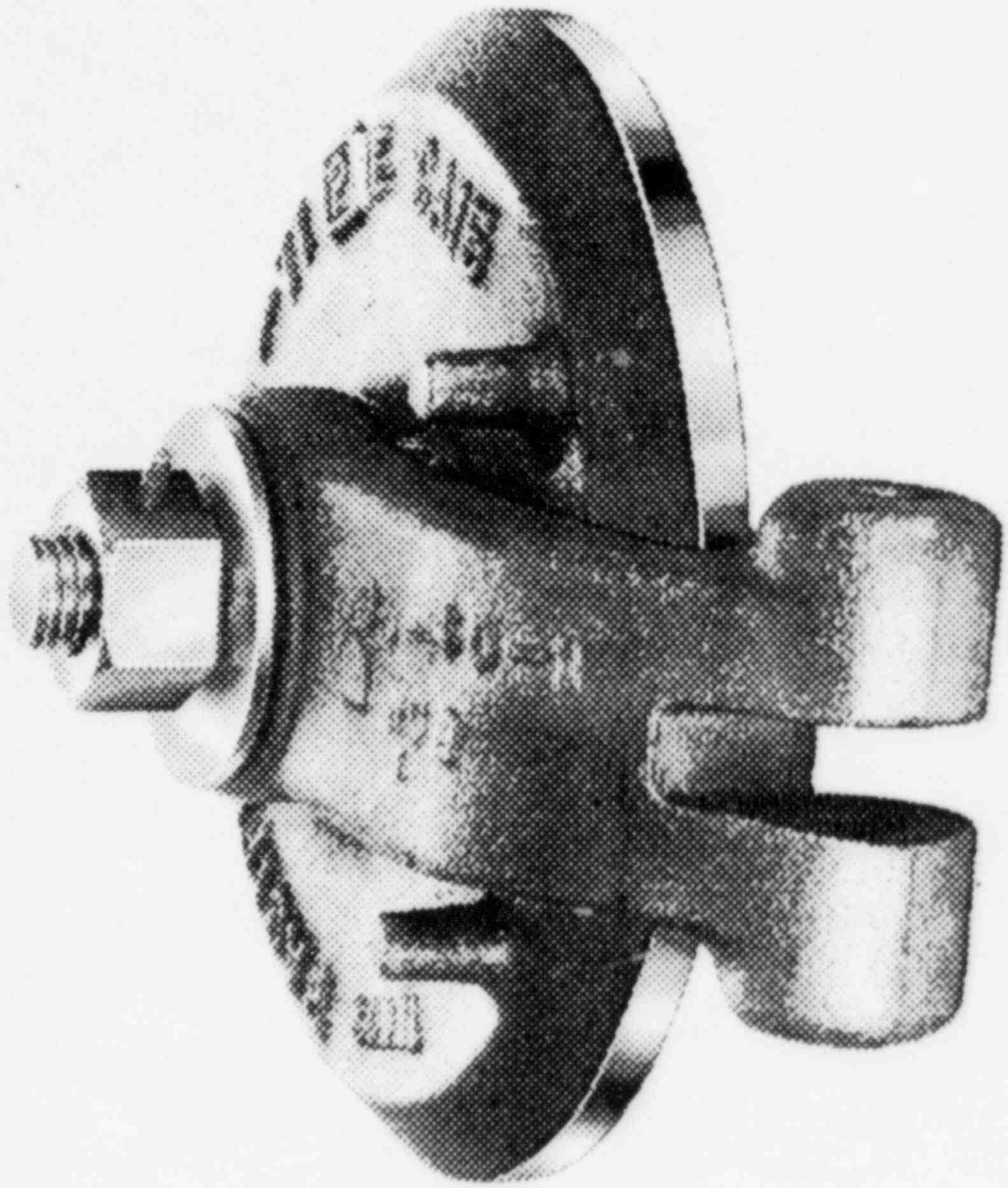
IN A HORIZONTAL PIPE



HIGH PRESSURE FEEDLINE CHECK VALVES

DAMAGE ASSESSMENTS

- OPENED AND INSPECTED MFW PUMP CHECK VALVES
- OPENED AND INSPECTED MFW 10" CHECK VALVES
- PERFORMED
  - VALVE LEAK CHECK
  - BLUE CHECKS
  - FLAPPER INSPECTIONS
  - DISC/SEAT GAP MEASUREMENTS



HIGH PRESSURE FEEDLINE CHECK VALVES

DAMAGE FINDINGS

- E. FEEDWATER PUMP CHECK VALVE, FWS-438
  - DISC NOT FULLY SHUT (5-10% OPEN)
  - DISC NUT LOOSE
  - DISC ROTATED COUNTER-CLOCKWISE
- W. FEEDWATER PUMP CHECK VALVE, FWS-439
  - DISC NUT LOOSE
  - DISC PARTIALLY OPEN (ANTIROTATION LUG LODGED-UNDER HINGE ARM)
- "A" FEEDWATER 10-INCH CHECK VALVE, FWS-345
  - DISC MOUNTING STUD BROKEN OFF AT BOTTOM THREAD
  - DISC EDGES DAMAGED FROM IMPROPER FIT
  - HINGE BADLY WORN BY DISC BOLTS
- "B" FEEDWATER 10-INCH CHECK VALVE, FWS-346
  - DISC FOUND AT BOTTOM OF PIPE
  - THREADED CONNECTOR ON DISC SHEARED
  - HINGE PIN ARM ELONGATED BETWEEN PIN AND ARM
  - DISC SEATING SURFACE HAS TWO DENTS
  - BONNET STOP SHOWS IMPACT DAMAGE
- "C" FEEDWATER 10-INCH CHECK VALVE, FWS-398
  - VALVE DISC NUT BACKED OFF AND WORN
  - DISC ROTATED AND COCKED IN SEAT (OPEN 20 DEGREES)
  - HINGE PIN BADLY WORN
  - DISC EDGES DAMAGED

PACIFIC CHECK VALVE DESIGN

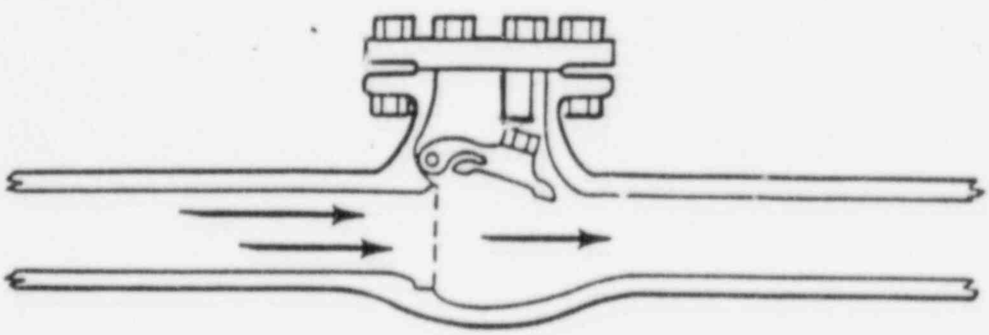
- VALVES ARE OVERSIZED
- FULL FLOW VELOCITY IS MARGINAL
- 90 PERCENT REACTOR POWER OPERATION

  12.5 PERCENT FLUID VELOCITY REDUCTION

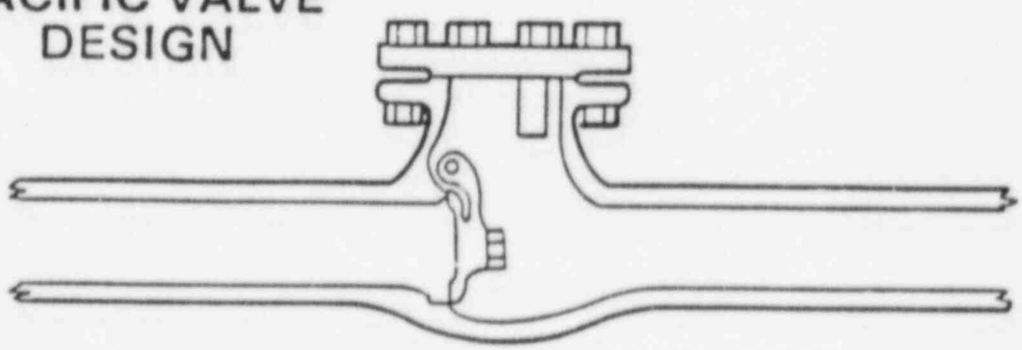
  24 PERCENT DISC LIFTING FORCE REDUCTION

  2 DEGREES FROM FULL OPEN

  1 TO 3 HZ RESONANCE; 10^6 CYCLES IN 12 DAYS

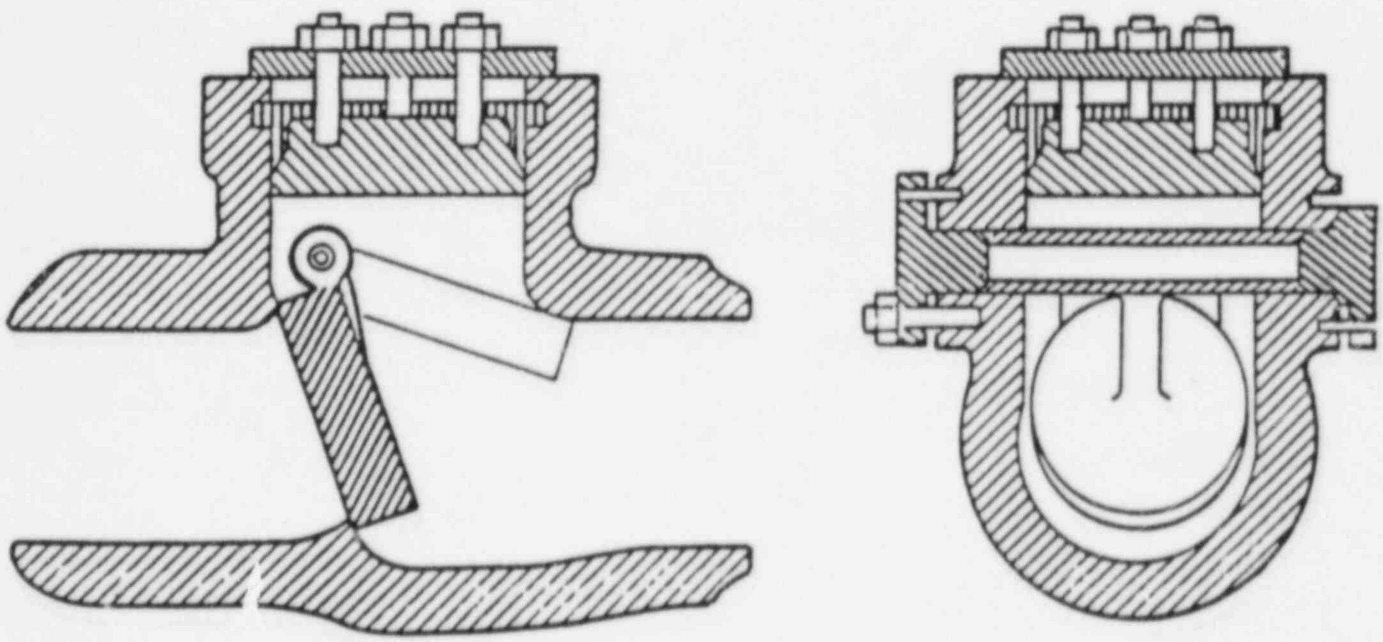


PACIFIC VALVE DESIGN



ATWOOD-MORRILL CHECK VALVE DESIGN

- o VALVE PROPERLY SIZED TO REMAIN FULL OPEN DOWN TO 70% FLOW
- o ONE PIECE DISC/HINGE ASSEMBLY PRECLUDES OBSERVED FAILURE MECHANISM



ATWOOD-MORRILL VALVE DESIGN

MODIFICATIONS ADDRESSING FEEDWATER WATER HAMMER

- o REPLACE 8 PACIFIC CHECK VALVES WITH ATWOOD-MORRILL VALVE DESIGN
- o PROVIDE IMPROVED IN-SERVICE TEST CAPABILITY FOR REPLACEMENT VALVES
- o SLOPE "B" FEEDWATER PIPE INSIDE CONTAINMENT
- o ADD CHECK VALVES, WITH IST PROVISIONS, IN EACH FEEDWATER LINE INSIDE CONTAINMENT
- o PROVIDE FOR AUTOMATIC CLOSURE OF MAIN FEEDWATER FCV'S FOLLOWING UNIT TRIP AND LOSS OF MFW PUMPS
- o EVALUATE ADDITION OF VOID SENSING DEVICE WITH CONTROL ROOM ALARM

GENERAL MODIFICATIONS

- INSTALL CONTROL ROOM INDICATION OF BLOWDOWN STATUS*
- PROVIDE AUTOMATIC BLOWDOWN ISOLATION ON AFW ACTUATION*
- EVALUATE POSSIBILITY OF PROVIDING FOR AUTOMATIC LOADING OF DIESEL GENERATORS ON LOSS OF POWER**
- EVALUATE ALTERNATIVES FOR PROVIDING AN IMMEDIATELY AVAILABLE BACKUP SOURCE OF OFFSITE POWER**
- INSTALL ADDITIONAL PROTECTION FOR AUXILIARY TRANSFORMER FEEDER CABLING*
- MODIFICATIONS TO PRECLUDE SPURIOUS ANNUNCIATION OF SAFETY INJECTION*
- MODIFY TSC COMPUTER FOR AUTOMATIC RESTART FOLLOWING POWER RESTORATION*
- EVALUATE PROVISION OF UPS FOR TSC COMPUTER**
- EVALUATE PROVISION OF UPS FOR BUSSES SUCH AS VITAL BUS NO. 4**

GENERAL MODIFICATIONS (CONTINUED)

- o DETERMINE AND CORRECT CAUSE OF SPURIOUS RED PHONE RINGING**
- o INSTALL CONTROL ROOM CLOCK NOT DEPENDENT ON AC POWER*
- o REVIEW CONTROL ROOM INDICATION OF VITAL BUS STATUS (CRDR)*
- o MODIFY CURRENT LIMITING BYPASS REACTOR BREAKER DESIGN TO PERMIT DG TO CLOSE ONTO 4 KV BUS WHEN BREAKER IS RACKED OUT*

NOTES: *TENTATIVELY PLANNED FOR CURRENT OUTAGE

**SCHEDULE NOT YET ESTABLISHED

CONCLUSIONS

- o THE MOST SIGNIFICANT ASPECT OF THIS EVENT IS FAILURE OF FIVE FEEDWATER CHECK VALVES

- o CHECK VALVE FAILURE WAS THE RESULT OF INADEQUATE DESIGN

- o IMPLEMENTING THE MODIFICATIONS OUTLINED ABOVE WILL ELIMINATE THE IDENTIFIED CHECK VALVE FAILURE MECHANISM AND IMPROVE PLANT PERFORMANCE